CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

INTEGRATED ENERGY POLICY REPORT

2005 ENERGY REPORT COMMITTEE WORKSHOP

ON STRATEGIC VALUE ANALYSIS FOR

INTEGRATING RENEWABLE RESOURCES TO HELP MEET

CALIFORNIA'S RENEWABLE PORTFOLIO STANDARD GOALS

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

FRIDAY, JULY 1, 2005

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APPEARANCES

COMMITTEE MEMBERS PRESENT

John Geesman, Commissioner and Presiding Member

James Boyd, Commissioner and Associate Member

Melissa Jones, Adviser to Commissioner Geesman

Michael Smith, Adviser to Commissioner Boyd

Timothy Tutt, Adviser to Commissioner Pfannensteil

STAFF PRESENT

George Simons

Dora Yen Nakafugi

Val Tiangco

Elaine Sison-Lebrilla

ALSO PRESENT

Ron Davis, Davis Power Consultants

Snuller Price, E3

Hank Zaninger, Zaninger Engineering

Brian Schumacher, CPUC

Jorge Chacon, SCE

Chifong Thomas, PG&E

Joe Kloberdanz, SDG&E

Mike Batham, SMUD

Dave Olsen, Tehachapi Study Group (via telephone)

Don Smith, CPUC

Nancy Rader, CalWEA

Hal Romanowitz, Oak Creek Energy

A G E N D A

A G E N D A (continued)

P R O C E E D I N G S

COMMISSIONER GEESMAN: This is a workshop of the California Energy Commission's Integrated Energy Policy Report Committee. I'm John Geesman, the Presiding Member of the Committee.

To my left, Commissioner Jim Boyd, the Associate Member of the Committee. To my right Melissa Jones, my staff adviser -- and I think later in the morning we'll be joined by Mike Smith, Commissioner Boyd's staff adviser.

I'm told that today is Workshop 41 in the 2005 IEPR cycle, so we have now past at least the daytime portion of the biblical standard of 40 days and 40 nights. So, on we go.

MR. SIMONS: Is this on?

COMMISSIONER GEESMAN: I think your microphone is one and I think someone is listening to us on a cellphone that has not pushed their mute button, or they may have just done so.

COMMISSIONER BOYD: You need to make the standard announcement, George, to people listening out there in radioland about the problems with feedback in this room.

MR. SIMONS: Yes, for those of you who

are calling in, if you could please mute your phone it would be greatly appreciated, because we can hear everything you say or do on the calling line. Thank you.

As Commissioner Geesman noted, we do have a very full agenda today. I want to thank everybody who's shown up, I realize that this is a Friday leading into a three-day weekend, so I appreciate you all showing up.

Just to go quickly through what we're going to cover this morning, I'll review the agenda, the participants, provide an overview of the Strategic Value Analysis approach and processes, and then we're going to go into individual presentations on results from the Strategic Value Analysis as applied to geothermal, wind, biomass and solar.

Geothermal will be covered by Elaine Sison-Lebrilla; Wind by Dora Yen Nakafuji; Biomass by Val Tiangco; and then I'll cover Solar.

Ron Davis from Davis Power Consultants will cover the combined mix of renewables, looking at the Strategic Value Analysis and the impact on the transmission system.

Around noontime we'll break for lunch,

and we'll have an hour for lunch, then we'll go into the afternoon session. And in the afternoon we'll look at some similar approaches at a statewide level using strategic value analysis by Snuller Price, looking at the Bay Area, with E3; Hank Zaninger looking at the Chino Basin.

Then we're going to shift and have a perspective from the Cal ISO, the PUC, and Investor-Owned Utilities and Public Owned Utility on Renewables Transmission Planning within the RPS Procurement Bid Process.

And so we'll have Brian Schumacher from the PUC providing us an overview of how the PUC looks at this. Hopefully, somebody from the Cal ISO will be showing up. I've heard that Jeff Miller is no longer with Cal ISO.

Jorge Chacon from the SCE will provide us their perspective; Chifong Thomas from PG&E will provide us PG&E's perspective; and Joe Kloberdanz from SDG&E will provide us SDG&E's perspective.

Mike Batham from SMUD will the provide us a public-owned utility perspective. We did try to have LADPW and IID come to the workshop, neither one could make it due to the large number of IEPR workshops that we've had recently. And just simply some other conflicts.

Dave Olsen will be calling in to talk about what are the findings from the Tehachapi study group. So, up until that point in time we've really been dealing with about a 50,000 foot perspective on renewables, transmission planning, how do we move forward on the RPS.

Looking down then on utility perspective, and then really focusing specifically on a regional effort where we have some very active participation in the RPS.

Before I start I want to go ahead and mention that the Strategic Value Analysis has been very much a team effort. The project is led by Prab Sethi here at the Energy Commission. We rely extensively on internal resources, I mentioned the CEC people who will be making presentations.

We also have renewable energy program folks who've helped us quite a bit in trying to maintain the quality of the work and the documents.

Department of Forestry has helped us significantly with development of a geographical information system, without which we would not have been able to begin looking at this stuff seriously.

We've had participation from the Cal ISO on providing us some review of the transmission work as well as people within the Commission in our Transmission and Electricity Analysis Office.

And if I've forgotten anybody I apologize.

Why did we start this? We originally started this work within the Public Interest Energy Research Group, not to figure out how to look at renewables with respect to the RPS, the RPS wasn't even on the boards yet.

We really started to look at how were we going to target renewables development from a research perspective in California. And our original analysis only went out to 2010.

The RPS was enacted, and based on that we began then to extend our analysis to look at bulk generation as well as extending the analysis out to 2017.

The approach is to identify the links between the electricity needs in California, across the system, in the future, with renewable resources.

So we began looking at how in fact can we begin to position the development of renewables going out past 2010, such that not only could they provide societal benefits, provide lower cost electricity, but also have a beneficial impact on the grid.

And then lastly what we wanted to do with that was, again, take it back to the original purpose of this, which is how would we target renewables research and development so that we could achieve those goals. So it's a five-step methodology.

First is that we, through Davis Power Consultants we identified, quantified, and then with the GIS tool mapped the electricity system needs going out through 2017. We looked at selected years -- Ron Davis will really talk more about that so I won't really cover it here.

Then we also updated all the renewables resource information that we had. Most of the information was 1980's vintage, so we had to actually back up and recalibrate and go out and get all new renewable resource information. We also needed a much higher level of precision than we had before.

So we went out and we actually captured that for wind, geothermal, solar, biomass; and even though I didn't put it here some small hydro and ocean wave energy resources.

We then went back and we looked at what would be the projected cost and performance trends for these renewable technologies, going out through 2017. And we relied on work that had been done internally as well as work that had been done by the National Renewable Energy Lab, the Electric Power Research Institute, and Navigant Consultant Company.

We then put the powerful analyses, the performance and cost projections and the powerful analyses together to investigate could these in fact, under the RPS requirement of a best fit least cost approach, could we get some reasonable results that would give us some perspective on whether or not we can meet the 2010 and 2017 RPS targets.

And again, the last part of this work is to then take that, those results, and roll it back in to what kind of goals would we have for R&D development in the future.

And this is a visual depiction of the

approach. Davis Power Consultants went and got data sets from the utilities, they ran the power flow analyses, they merged the cases, by the way, so that we weren't simply looking at a single utility at the time but we were looking in fact at the entire growth of the system from all the utilities and the public-owned utilities up to 2017;

We identified what we call "hot spots," or areas where there would be reliability problems that would emerge in the future, primarily based on the NERC N-1 contingency analysis approach.

We then -- well, actually DPC developed what they call the weighted transmission loading relief metric, which is a way to begin looking at okay, if we have problems in specific locations in the grid, where we have problems, how can we quantify that problem and how can we quantify it in a way so that we can measure it relative to other spots in the system.

And then they came up with a generic megawatt solution, which then allowed us to begin inputtimg specific renewable transmission or generation based on what was located approximate to that hotspot. And again, this was all done at

GIS overview.

Now, at the back end of today's agenda there are a number of questions that we've asked, that we think are good discussion items. And I brought this up because I think, as we go through the presentations today, this is the kind of thing that we would like people to be thinking about.

Is the SVA a valid and reasonable approach for assessing the sate's ability to meet the RPS goals and also to determine the impact of developing out the renewable resources on the grid?

So, again, we've got this 20 percent by 2010 goal, what's the impact of the grid developing that?

Do we actually have sufficient resources within the state to meet the RPS goals? In earlier workshops we looked at out of state renewable resources and found in fact that there are some significant transmission constraints to bringing in by 2010 renewable resources from outside of California.

So, that really then narrows down the solution to what do we have instate.

Are the cost estimates reasonable and

appropriate, and if not what we would like is -- we will not pretend that we have all the answers, and we would really love to have input on if these are not reasonable costs, what are reasonable costs? What should we be looking at?

Similarly, are the time frames for development and more employment of the technology is reasonable, and if not what would be your feedback to us on what would be reasonable time frames?

Ron Davis is going to talk about the blend of renewable resources, and again there's no correct answer. What there is is an approach, and so is the blend appropriate, and if not, have we missed something in the blends, have we discounted something, should be we look at something that we haven't looked at.

On the transmission side, is the transmission evaluation methods appropriate and reasonable? Are there other things that we should be looking at that we've entirely missed? We need to understand that.

And then what approaches should be used to take into account transmission needs and opportunities when we begin to build out the RPS in California?

And with that, we'll go ahead and get started.

COMMISSIONER GEESMAN: George, let me ask you, we provided an opportunity for people to submit written comments after today's workshop?

MR. SIMONS: Absolutely. That's a great question. Yes, we will provide an opportunity of, you know, I don't think, as you mentioned, this is going to be an ongoing process, I don't know what the time constraint is for the IEPR.

COMMISSIONER GEESMAN: Why don't, why don't we ask for written comments on the subjects of today's workshops by July 22nd? That's three weeks from today.

MR. SIMONS: Okay, thank you. The first presentation we have is by Elaine Sison-Lebrilla, on Geothermal.

MS. SISON-LEBRILLA: Good morning. George has given a general overview of the strategic value analysis methodology, so I am just going to go straight into giving an overview of the SVA results for geothermal. Also, to go through how we have done our cost modeling. And the forecasts we have used to compare our levelized cost of electricity numbers.

In a previous workshop, the Renewables workshop on May 9th, I presented the geothermal technical potential numbers, and it's approximately 3,800 megawatts throughout the state.

And they're located in these utility service areas, and basically follow the line of the KGRA, the Known Geothermal Resource Areas.

The strategic value of geothermal results. We went through a whole series of iterations that George briefly described, and our final results were, for 2010, for geothermal, we believe that there will be approximately 15.04 megawatts available in economic potential.

And for 2017 we believe there will be approximately 27.73 megawatts. And these are without transmission costs included, and assuming a production tax credit.

COMMISSIONER GEESMAN: Elaine, have you confined yourself to in-state geothermal?

MS. SISON-LEBRILLA: Yes, this is for California.

COMMISSIONER GEESMAN: So you haven't taken into account any of the resource that your earlier presentation has identified in Nevada?

MS. SISON-LEBRILLA: No, this is all in California. We have not included. I will go further. Geothermex did our initial resource assessment and they looked at parts of Nevada and California, but we here have focused specifically on California.

COMMISSIONER GEESMAN: Thank you.

MS. SISON-LEBRILLA: This is without transmission. With transmission costs, that were provided by Ron Davis, we estimated that by 2010 we will have 1485 megawatts available in geothermal economic potential, and by 2017 2638 megawatts, approximately.

Our SVA geothermal approach. What we did was identification and qualification of the resources. We did a calculation for the cost of geothermal electricity generation, and then we started adding new geothermal resources on to the grid.

Our SVA geothermal team consisted of Energy Commission staff, Geothermex, McNeil Technologies, Davis Power Consultants with assistance from Anthony Engineering and Power World.

Geothermex did our resource assessment, and they also provided some of the costs that we included in our model. McNeil Technologies, with CEC staff, developed the economic model, and Davis Power Consultants, with Anthony Engineering and Power World, they essentially did our transmission modeling.

How we calculated the cost of geothermal electricity generation. We used an economic cost model that calculated the levelized cost of electricity for each resource. We calculated with and without PTC, the Protection Tax Credit, and we calculated with and without transmission costs that were given to us by Davis Power Consultants.

We created base cases for dry steam, flash, and binary technology. The methodology is a revenue requirement approach. The model calculates the levelized cost of electricity in current dollars and constant dollars.

What I'm presenting to you is the current dollar table, but the constant dollar is in the white paper that is on the website.

The analysis considers what is return on on investment, recovery of capital, expenses, O&M costs, and taxes over the economic life of the project.

It calculates the levelized cost of the electricity for all the geothermal resource areas.

These are the general assumptions that we utilized. A 20 year economic life for dry steam, flash, and binary technology. An annual increase in wealth productivity at 4 percent, and you can read down this list.

I have a lot of slides, so I'm going to try and go quickly. And the hard copy that you have received on the table inserted a few other slides in it, so my updated presentation will be posted on the website at the end of today.

Projecting geothermal performance in cost. Our performance projections were based on technology development trends, by Geothermex, EPRI, and Navigant. We assumed moderate development of geothermal technology.

Our cost projections were based on their geothermal resource assessments. We assumed cost reduction trends in drilling and subsurface and above ground facilities, and we included technology development trends from studies done by Geothermex, EPRI, and Navigant.

We calculated the levelized cost of

electricity from 2005 to 2017.

These are the assumptions for dry steam, capital costs and O&M. I won't go over all of these numbers, but you do have it with you, and it's also in the report.

And these are the flash steam capital and O&M cost assumptions for each resource area.

For binary, these are the capital costs and O&M cost assumptions.

These are the --

MR. SMITH: Elaine, quick question. Could you go back to two slides ago? That one. Could you clarify, consultant C, the high and low scenarios are the same numbers under "development." Is there --?

MS. SISON-LEBRILLA: Well, the low cost is the number we got from Geothermex, and it's consistent with the methodologies they used. For the consultancy high cost the development potential is the same, but the cost was different.

We got the high cost from a conversation had with Cal Energy, so we thought we would just throw that on the table also. But we typically use the low cost, because that was part of our methodology, and all of these numbers are based on the Geothermex resource assessment.

MR. SMITH: Okay, so the development potential --

MS. SISON-LEBRILLA: Is the same.

MR. SMITH: -- is just the technical resource potential regardless of cost?

MS. SISON-LEBRILLA: That's correct.

MR. SMITH: Thank you.

MS. SISON-LEBRILLA: So, for dry steam, this is the levelized cost of electricity of the dry steam resources only, at the geysers. And this includes no transmission for 2005, 2010, and 2017, with and without PTC.

This is for the dual flash, the resource areas that have the capacity to utilize the dual flash technology, Calistoga, Raleigh, Coso, Lake City, the Medicine Lake area, Niland, Radsburg, Salton Sea and Sulphur Bank.

And these are the PTC's, this is with and without PTC for these given years. No transmission costs added.

This is for the binary, the resources, the resources that can use binary technology. And these are transmission costs that we received from Davis Power Consultant.

And what we did with our LCOE's is compare them with the market price referent, and several forecasts that were done here at the Energy Commission and by E3 through the CPUC process.

And these are the numbers that we compared them to. And these will become more evident when I show the graphs of all of our LCOE numbers compared to these forecasts.

This is the LCOE for dry steam, the geysers, with transmission costs.

And this is the graph that I'd mentioned. The brown, the bottom is the current CEC 2003 forecast, --

COMMISSIONER GEESMAN: Well, let me jump in here. When you say "the current 2003" --

MS. SISON-LEBRILLA: I'm sorry, it's 2003, it's not current.

COMMISSIONER GEESMAN: That's the one we adopted in the last IEPR cycle, which included gas costs assumption in the $3 range for the duration of the forecast.

MS. SISON-LEBRILLA: Right, right. And so that's why we utilized the MPR comparison for 2010.

MR. SIMONS: Let me just quickly interject. We wanted to take the most conservative approach that we could, so we started off with what we recognized as an out of date forecast, the 2003 forecast.

And as Commissioner Geesman has noted, it was based on very low natural gas prices. We wanted to also have something that we could hang our hat on. I wanted adopted forecasts wherever possible. We have not yet adopted the new price forecast.

So we then looked at what had been coming out through the PUC, this is why we have the PUC natural gas combined cycle projections in there that E3 provided to the PUC.

We also knew that MPR for 2004 was available, both in terms of baseload as well as peaking. So what we tried to do is reference these LCOE values against those adopted numbers, or those numbers that we felt could at least -- people could say well, yeah, we know people are going to bid into the MPR, so if in fact the LCOE values are lower than the MPR that gives us reasonable assurance that that technology is cost competitive.

So that was really the approach. We were trying to gauge the levelized cost numbers against something in the marketplace, realizing of course that these are cost numbers, these are not prices.

COMMISSIONER GEESMAN: And is there an MPR plot on this graph?

MS. SISON-LEBRILLA: The MPR is 6.05, and it's a straight line right here.

COMMISSIONER GEESMAN: Okay.

MS. SISON-LEBRILLA: So, that's why it wasn't plotted. For the geysers, none of the geyser's potential will be available by the 2010 time frame. But we also plotted the combined cycle here, and so you can see, by around 2012 some of the potential can be available, with PTC and no transmission costs, for the LCOE's.

These are the LCOE numbers with transmission costs for the resources that can utilize dual flash technologies. And this is Salton Sea, below again the MPR, a little above six cents line here, so for Salton Sea there is a possibility of bringing them on board by 2010.

When you include PTC and transmission costs in the LCOE calculations, and also PTC with no transmission costs, which is this one.

So by 2010 there is a potential to bring them on, when you compare the LCOE that was calculated with the forecasted LCOE costs.

And this is for the resources that can be utilized, the binary technologies, these are the LCOE's with transmission. And this is an example of one of the resources, at Heber. And the MPR is, again, here, and so -- and this is at 2010. And this is PTC without transmission and PTC with transmission.

So, essentially this is in tabular form. The orange areas, based on our input from Davis Power Consultant and they have done the transmission modeling, there were certain areas, certain geothermal resource areas that, when put on, when the capacity, or the economical potential was put on to the grid, would provide detrimental effects to the grid.

Therefore we did not include them in our calculations for the economic potential. And these areas are Coastal Hot Springs, Honey Lake, Long Valley, the Mammoth Pacific Plant, Mono Long Valley, and also Landsford and Sespe Hot Springs.

So those were automatically eliminated

from our calculations. So by 2010, when compared to the MPR, for geothermal, there would be a 1485 megawatt economic potential transmission with PTC, and no transmission with PTC would be 1504 megawatts.

COMMISSIONER GEESMAN: Now, in terms of your methodology for those orange areas, that was based on a single snapshot of the grid, assuming no other improvements to the grid were made?

MS. SISON-LEBRILLA: Yes.

COMMISSIONER GEESMAN: Okay, I'm jus trying to look at that from the perspective of a developer in any of those reasons and trying to understand the limitations of the methodology we've utilized, because it's real hard to take a single snapshot of the grid and have any confidence that that's the way the grid will be at any future point in time.

MS. SISON-LEBRILLA: Yes.

COMMISSIONER GEESMAN: Thanks.

MR. SIMONS: I would like to make one comment to that, John. Just for clarify purposes for project developers, again, we wanted to have a consistent approach. That doesn't mean this is reality. There may very well be develop in those areas.

We had to go with, as Ron Davis will talk about later on, we had to go with what transmission capacity additions had been approved, what new generation was approved.

We also were only looking at a single, as John pointed out, a peak instant during the summer. But, we wanted to be consistent with that methodology, realizing that this was a conservative approach, again, and realizing that development may very well occur in areas that, in our initial analysis, have indicated that there would be transmission problems.

So, this is going to be common throughout all the resource work here, that those assumptions were made. We know that the SVA is an iterative type process, and as development does occur, as new generation is planned, as new transmission additions come online, then you really do have to go back and take that into account.

COMMISSIONER GEESMAN: Yes, and as I look at this particular table, with the exception of Sespe, those all look like east side resources that obviously would be impacted by whatever transmission development might be associated with additional imports from states east of California.

COMMISSIONER BOYD: It was important, George, for you to add that caveat, for the audience's benefit. Thank you.

MS. SISON-LEBRILLA: And these are the other tables, comparing to the CEC wholesale, the CPUC-E3 forecasts, and the combined cycle forecasts for 2010.

For 2017 we have the same comparison, but for 2017 we utilized the combined cycle comparison. And so, for 2017 we estimate that 2638 megawatts would be economically available with PTC and transmission costs included, and with no transmission costs and PTC included it would be 2773.

So, in summary, the technical potential for geothermal is approximately 4,800 megawatts. Utilizing the SVA methodology we calculated the economic potential to be 1504 megawatts by 2010, 2772 by 2017.

We understand that there are transmission constraints and we tried to look at that through our transmission modeling, but we still feel that developing geothermal can significantly contribute to the goals of the RPS.

This is my contact information. The white papers are available at the website. Geothermex's resource assessment is also available on our website and also on Geothermex's website.

MR. DAVIS: If I could, I'd just like to comment on the transmission. What we did in this approach, when we did the individual resources, we looked at the transmission requirement that would be required to bring that resource and connect it to the grid.

And we looked at if it overloaded the transmission line what transmission upgrades would be there for that particular resource to get it out.

So as you look at the geothermal, the wind, and the biomass, and you look at the transmission costs, those are all based on getting that individual resource out to the market.

Later on this morning, when I do the integration, what we do then is combine all the resources together and then look at what additional overloads, if any, are created by doing an integration and putting six to eight thousand megawatts of renewables on the system.

Uh, now Dora's going to come up and talk about the wind study that was done.

MS. NAKAFUJI: Good morning, everyone. I'm Dora Yen Nakafuji, and I'm the technical lead for the wind energy resources.

What I'll now talk about is the economic results that we generated from the SVA analysis for wind resources, focusing on our criterias on how we got there.

So basically I'll go over the SVA wind results, tell you how much we have by 2010 and 2017, where they're located, and when we anticipate those, in terms of a priority, when they will come in.

And then I'll focus, go back and review in a little bit more detail our approach, our filtering criteria, as to how we got to those results and the feasibilities and priorities. And then comment on where we're going to go from here, the next steps.

In June we presented the technical potential for wind, and at the 70 meter height there were significant resources within the state. Again, with wind, this analysis concentrates on in-state resources and it doesn't pull in the out of state resources.

The technical potential for wind, as you can see, is quite a large number. So we wanted to hone that down, focus that down, and see what's developable.

So applying the SVA methodology to go back to assess the amount of resources we have and how do we prioritize those resources and how do we integrate these resources, so the time frame we chose is the 2010 checkpoint and also a 2010 goal, meeting our RPS goal.

Two evaluation criterias that we used following this approach -- we were able to identify locational, where these resources should be placed. In terms of wind it's not like geothermal, where it's the location of that resource, it's more of an area.

So we tied the transmission hotspots, the weaknesses in the grid, the reliability issues, identified those areas, and tied them with the wind resource area.

And in terms of temporal evaluation, we had to know what time frame they would be feasible, in terms of priorities of where we need to develop within the state, and also the timing of bringing in the transmission, looking at the technology of the wind resource.

Because wind resource technology, or wind generation technology, is improving. And as we can see, from the Altamont down to the Tehachapis there are -- and even in Solano -- we see new systems with higher efficiency, better performance and better reliability.

So all of those things impact our temporal evaluation, and as George said, it is an iterative process, and by following this methodology we can go back to reevaluate many of these results that you'll see today, but we're going to need to continue doing this as time goes on.

In terms of SVA wind results, here it is. So I'm just going to present this, and then we'll go into the details a little bit more in the coming slides.

Technical potential, again, for high wind speeds it's very high, over 14,000 megawatts. Lower wind speeds, you can see, needs more land resources as well as wind resources, but the technology needs to catch up.

So we're anticipating that coming in

around the 2017 time frame. So you'll see that in the economic potential.

The results from the locational evaluation, time, the resources to the hot spots, we have close to 7,000 megawatts of wind.

Now, that doesn't mean all 7,000 is going to be developed, as we continue the -- they'll come in to pieces, based on transmission availability, the reliability, and what benefits they will have on the grid.

And then at low wind speed we're about 20,000 megawatts.

On the temporal analysis for 2010 the results show that, from the hot spot analysis, is that approximately 2,473 megawatts of high wind speed.

As you notice, the low speed, we didn't put anything there, again anticipating that the technology for low wind speed will really mature by the 2017 time frame and by 2017 you can see the additional resources projected there, at around 3,438 megawatts for high wind resources and about 304 megawatts for low wind resources. And this is development throughout the state.

So, locationally, this is where you can

see the megawatt solutions coming in. A lot over in the Solano. It's color coded by year, 2010 we anticipate development that's in yellow, and then pink is the 2017 potential.

And the focus here, a lot of it is looking at southern California development, with some in northern California, the Altamont area, Alameda, and also the Solano areas.

So how do we get to these results? And also how are we going to prioritize the development throughout the state? We can't just put all our eggs in one basket and focus on one area, we need to look at a strategic plan on how all these areas will be developed, and what's the most benefit to the entire grid for the state.

So the strategic roadmap, the SVA approach, really lays out this process. We looked at the wind resource assessments that George talked about at the beginning, and then we looked at the transmission hot spots and then related that to the technical potential for wind and identified areas where we could concentrate.

We couldn't do the entire state in the study, so we focused on the area with the most potential to meet the RPS by 2017.

Then we looked at economic alignment parameters. And these things tie with the feasibility, the prioritization of the LCOE, and al these different factors. The more you load there, the more filters you put there, obviously the less and less megawatts you have.

So, as we continue on with the SVA analysis, depending on what we put in there, these are all filters, we can change the solution. But based on our economic filters that we've chosen, the results is what we're presenting today.

So the resource locations are then, these are the solutions basically, baaed on our two time frames. And then we develop an integrated strategic road map by combining all the resources together, and that's what Rod's going to be talking about.

To walk you through visually in what we did with the GIS analysis and what George talked about, with the multiple steps, we're taking the technical assessment results. So for this I'm showing the wind results.

Right now, as you can see, this is a high wind area. We just took an area, no particular area, but just an area for wind. And this is a good resource.

From there we overlaid the transmission, the existing transmission capacity capability substations, all of that information on transmission. And then DPC ran their analysis, their continuity analysis, and found a hot spot.

So we prioritize the value of that resource based on how much value it had in resolving a, in providing relief to the grid. So that was identified as a hot spot, and then what we did is we knew that wind had a resource area.

So we created a buffer zone. So all the wind in that buffer zone, and it could be 10 miles, it could be 20 miles, but what can be economically built within that time frame, we created a buffer zone, and that's what we analyze.

So that's how we generated the numbers for analysis. And so, for example, these are the hot spots that were shown in the analysis that Ron ran, and their prioritized based on impact to the grid.

So the hotter the color, the hotter the hot spot. So we want to try and develop as much in those areas, and then the cooler the colors there are still benefits for developing there. There's positive energy benefits, but there's also positive public, non-energy benefits too.

COMMISSIONER GEESMAN: What was the size of the buffer zone?

MS. NAKAFUJI: For our analysis we chose a ten mile radius.

COMMISSIONER GEESMAN: Then you would assume a uniform distribution of the resource within the buffer zone?

MS. NAKAFUJI: Well, actually the resource is tied to a substation. So it's an injection point for a substation that can actually handle the amount of resources coming in. So they were tied to a substation.

COMMISSIONER GEESMAN: Okay.

MS. NAKAFUJI: So you can see here, substation's blowup, the red ones here in southern California, we probably want to try and bring as much of this wind resource over here that's been identified to these substations.

The only issue is also transmission cost. So we provided a transmission cost based on infrastructure but we didn't go into the details obviously of the land rights, land use, and all of those other, you know, the detailed costs, and that's where the next steps will be needed.

COMMISSIONER GEESMAN: Sure, but if you were 11 miles away from a substation, your analysis ignored that resource?

MS. NAKAFUJI: Well, for the first cut, if you were 11 miles, and for wind we had a little bit of, our circles weren't exactly circles, they were kind of morphed to fit the resource. If there was a very high wind resource they we visually kind of included it.

So it's within that range plus or minus a small amount. But --

COMMISSIONER GEESMAN: How did you draw a boundary with something other than a circle?

MS. NAKAFUJI: An oval?

(laughter)

COMMISSIONER GEESMAN: But based on what?

MS. NAKAFUJI: Based on the shape of the wind resource. The wind resources tend to be trapped in a valley or a canyon area, so they were elongated rather than --

COMMISSIONER GEESMAN: Okay. And your data source for defining the wind resource was what?

MS. NAKAFUJI: That was from the detailed wind resource assessments that we had. That's what the grids were on that map that I showed.

COMMISSIONER GEESMAN: So, for the locational evaluation of wind these are the details. There were 19 counties that all had significant amount of wind resources, or an amount of resources.

So what we did was focus on the ones that had the potential to be developed by our time frames. So the top six, Alameda, Solano, Riverside, San Bernardino, San Diego and Imperial, those are the ones we concentrated on for the transmission analysis and for the studies for high wind and low wind speeds.

So these are the result for them. In terms of potential. Now, the first slide I showed was the actual results. So this is, I"m now walking you through the details, and we used these as guidance and input for Ron to be able to run this analysis and say "well, how much can I get out of Alameda County?"

Well, I"m going to try to put on all 132 megawatts, but if I overload the system I'm going to back down a little bit. So you'll see as we continue on, in San Diego there's 756, but in our solution we were only able to put on 500 megawatts.

So I wanted to explain that here, so you don't go "oh, there's a discrepancy in these numbers." So this is the results for the locational evaluation.

The Tehachapi area we looked at a resource. It's not close to a hot spot, it's so far removed, there's no transmission out there, but it's such a huge resource area that we couldn't just ignore it.

So what we did was we looked at it as far as the resource potential, and then through the analysis we were looking at, through the integration analysis we could look at well, what amount of transmission upgrades, how can we pull it in, and where do we need to beef up the transmission buildout to accommodate that amount of resources.

So from the transmission analysis that DPC ran we came up with what's called system impact ratios. And I think, without going into the details of all the WTLR's and the aggregated megawatt contingency overload factors, what it boils down to is these impact ratios.

And the negative impact ratio basically means by adding the generational resources at that spot you actually decrease the contingency overload situation for the grid. So it's a benefit for you to be able to build that resource at that point to the grid.

So a negative impact ratio is good, it's a decrease of the contingency overload. So what we're looking at for these counties, it gives us a priority of where we're going to get the maximum benefit. It's not to say that you're gong to follow this chart and go and be able to develop a baseloads chart, but it gives you an idea of what resource, or what location, is going to provide great benefits.

So San Bernardino has a lot of benefits, but it's not a huge load center. Alameda is pretty good, it's a slight negative impact so maybe that's a good area. Solano is actually excellent in terms of resources and it also has a negative impact ratio.

So it gives you a feel of where to then

prioritize some of this development. And also, for us on the research side, where should we focus more development in terms of our R&D dollars.

COMMISSIONER GEESMAN: Now, you must have made some assumptions then as to time of day and time of year, as to when the generation would be available?

MS. NAKAFUJI: It's peak conditions right now, for wind. So for wind we get summer peaks.

COMMISSIONER GEESMAN: So you assumed then that the resource at some capacity factor, availability factor, would be available at summer peak.

MS. NAKAFUJI: Correct.

COMMISSIONER GEESMAN: And was that uniform across your geographic areas?

MS. NAKAFUJI: Well, in terms of capacity factor, yes. And it's summer conditions, yes. So that is consistent.

COMMISSIONER GEESMAN: Okay.

MS. NAKAFUJI: So for the Tehachapi area, the LA-Kern, it's a positive impact, meaning the injections to the grid down there, based on current day grid, transmission grid, again no development, no changes to the existing layout, it's a positive impact.

But, as Ron indicated, as time goes on there will be upgrades to the system that could be reassessed and perhaps that could change. It's not too positive, but it is a positive impact we show.

For low in speed we followed a very similar type of approach, and the three circles, again they could be elliptical or oval, those identified the areas that we did our low speed wind analysis for integration.

And again, you can't really see, but there's little blue spots over here, little dots on here, close to the wind resource, the light green is the low wind speed region, as you can see, and then the purple and the green is the high wind speed areas.

So there's a lot of wind speed potential in the smaller area. And if we're able to tap some of those by going into the substations around this area to provide significant amount of low wind speed potential.

So the economic evaluation. Again we looked at generation costs, LCOE's, straight on, but we also added some transmission component, what we call transmission factor in LCOE, and came up with a total LCOE.

So for our prioritization, in terms of looking at the cost, we wanted to be able to add some amount of transmission into it. And that directly guided Ron in terms of what resources were chosen for his detailed analysis.

Now, this economic LCOE conversion is just the general LCOE comparison. So the solid line that Elaine showed in geothermal, for the wind the solid line indicates the wind LCOE with PTC and no PTC.

And the blue here is again our 2003 CEC projections, as Commissioner Geesman pointed out, is low on the natural gas costs. But what we were after is this intersection point, highlighted by this circle here.

The intersection basically tells us that, whatever this generation resource here, would be just as economic as the natural gas, by this time frame. So initially that was what we were after.

But given that this projection is conservative, we started looking at other baselines for comparison. So you can see the wholesale price for costs, PTC forecasts here, and then this one is the combined cycle cost, current dollar, E3's projections.

So for wind we are already, we're well below those two projections. So in terms of economics we're already there in terms of time frame of when it's economically feasible.

The market price referent is somewhere around here, actually it's 2004, so it's off the chart here, so again, with the PTC we're economic, but without the PTC we're still pretty close.

So based on cost it also gives us a gauge on what sites to go and focus resource-wise. Now, those chart actually adds in some of the transmission costs anticipated if you were to solve the overload conditions that Ron talked about.

And the overload conditions would require sometimes minor sometimes major transmission upgrades, like re-conductoring the lines. And those factors were included in this chart.

So, as you can see, Alameda, Riverside, San Bernardino, pretty good. But if we wanted to tap into the resources in Solano there's a significant cost in terms of LCOE, they're slightly higher LCOE.

But if you compare back to this chart we're probably right on par by 2010 with comparisons to combined cycle. So around 7 cents per kilowatt hour, just under that.

So overall, the SVA showed, the economic and the technical, showed us that there are a significant amount of wind resources in the state. And we followed this approach, basically the technical to the economic. We looked at the comparison and then looked at some environmental benefits for our criteria.

So for solar and biomass they may have others that they are looking at, that they had used in their analysis.

In terms of next steps, where do we go from here. Well, obviously there's an integration component. Our results were only for a single resource. The integration needs to be done, and Ron will follow up with a presentation on the integrated mix, the solutions that were generated from there, and also the proper mix of conventional and renewable resources.

But there's another step to be taken, and that's on the operations side. And so what we've done is initiated the Intermittency Analysis Group to look at how the SVA solutions will match and address some of the utility resource needs, how we can help use this methodology to address some of the operation issues in terms of taking the next step of incorporating a production cost model.

So it's no longer just a snapshot it time, it will be more of a realtime looking at conditions in a region based on the utility needs and determining the commitment needs, dispatching requirements, and really looking at how do we operationally inject these solutions at the sites.

And also we really need to engage the utilities, and through the Intermittency Analysis Group we are starting that interaction with various utilities, and through phone conferences and also as the results are forthcoming we'll be able to share it with them and have them be able to vett it out, and also be a test case to try out some of the solutions.

And then provide feedback, back into this whole energy planning and future transmission planning requirements.

So, in summary, there are significant resources in California, with definite transmission issues, and we need to prioritize it based on some strategic vision, but also a way of strategically looking at the resources and prioritizing them.

And SVA allows us to do that. Now, we have shown the results for wind, but again it's for all renewables.

And this is my contact information for details of what was shown in these slides. There is a full report that's also on the web, and you're also free to contact me for more information.

COMMISSIONER GEESMAN: Thanks, Dora.

MR. SIMONS: I also want to make a couple of comments. First off, there's more handouts that'll be in the front. There's agenda and presentations as well as -- we should have copies of the documents available.

I also wanted to mention, on the resource assessments, I think it was maybe indirectly raised on the wind, but the resource assessments have a lot of information in them.

The wind resource assessment, for example, is a billion points, literally, in the state, on a 200 meter by 200 meter grid, with five different elevations that you can look at, power density and wind speeds.

Those are predictive models, okay, but nonetheless this is the state of the art that's being adopted across states in the country. It's something that, we got our resource assessment from True Wind, who's also providing that on a consulting basis, obviously, to other states.

But very similar to what NREL is doing. And it's also based not just in plan predicted, but in fitted points within the state of California. So we are in fact truthing the resource assessment.

I also wanted to make the point that, again, the SVA, don't look at the results as absolute values. I mentioned that earlier. But look at the SVA as an evaluation tool. And Dora mentioned the fact that we're engaging with the utilities to try to adopt this method.

And in fact PG&E has offered to be a host utility to really look at how could we now take and apply this to a IOU for example, and see what would be an approach that could be developed if there are any sorts of problems with this approach, that could be ironed out.

So again it's going to be an interactive process. I also wanted to mention that, on the transmission based approach, that our first cut was to look at where we could put in transmission that would not require, where we could locate renewable generation, excuse me, that would not require new transmission additions.

Now we know, again, in the Tehachapi down in the southern, eastern portion of the state, that there will in fact be transmission capacity. That's not taken into account. So, again, you're going to see results that, well, wait a second, we know that transmission's going to be coming in, so some of this generation will come in.

But under the assumptions that we made we had to be consistent, so we let that alone.

So we wanted to look at first, where can we put in generation that would not require new transmission additions, and then secondly, based on where we could put it in, where could we put it in that would have a net benefit on system reliability.

Ron also wanted to make a couple of comments, and then we'll go ahead and move on to biomass.

MR. DAVIS: A couple of comments. We looked at the summer peak only. We really need to look at a spring or fall. We really need to tie in to production costing.

We did some preliminary stuff that we weren't able to complete, but in talking with PG&E and doing some stuff we know that the flows on the wind is going to be more critical in the spring and fall, and especially in the south and north direction when we look at the Tehachapi, because of those, and that needs to really be a followup.

The other thing -

COMMISSIONER GEESMAN: Let me say on that, Ron, I think you're right. I think where we ought to be trying to move on this is to replicate the criteria which a utility would utilize in planning its transmission upgrades.

MR. DAVIS: Yes. One of the things we did do on the Tehachapi is, remember when the utilities, the IOU's come up with their conceptual plans for transmission -- and SCE had done the stuff for Tehachapi.

We did follow that closely, and tried to look at that. But we tried to do it independently and then go back to look at how close we would be to what they are.

We know that, in the Tehachapi study that, when we showed that positive ratio, just a comment is that we did not try to do the planning for them and do the solutions, and so they have planned some other additional upgrades to get it close to the load centers, and that ratio will come down as a build more upgrade of their transmission system to get it to the load.

And we'll see that come down to be a better number.

COMMISSIONER GEESMAN: Now, in Tehachapi you're only looking at upgrades to the Edison system, or did yo also incorporate the various upgrades to the PG&E system that have been mentioned?

MR. DAVIS: No, we did not do the PG&E. And that's one of the things, we know that the south and north is going to be a problem trying to get through NP15.

COMMISSIONER GEESMAN: Yes.

MR. DAVIS: The other thing I want to comment on is that when we did the summer we didn't do the maximum wind generation. We looked at what the summer wind conditions were, and for example we only assumed like 25 percent of the capacity would be available at time of peak.

So we didn't, if for example San Diego was 756 megawatts, we didn't look at that total in the summer wind, we did a percentage of that. And if that still causes a problem in the summer peak then we know there has to be upgrades.

But we do know that there's going to be other upgrades that are going to be required as you start to look at the spring period, because there will be more flows and the changes will be a little different.

COMMISSIONER GEESMAN: Yeah, I guess, I have a question there as to the amount of regional variability it's appropriate to assume, as opposed to simply having one constant assumption statewide. And also what prospects might exist for over-generation in some of those locations, depending on what assumption you use.

MR. DAVIS: Yes. I think that, assuming a constant is one we want to look at, and that's in the intermittencies, I think there's one of the things you want to cover.

And also the fact that, as we start bringing in some low wind as we get past 2010, does that smooth it out so we get a little better capacity factor, because now we're blending high and low and we're getting a little more efficiency as we blend some more of these resources, so we're not seeing the spikes to the high wind.

And then it's really important to look at the production costs and look at the seasonal and see how the effects overall are. So I just wanted to make those comments. Thank you very much.

MR. SIMONS: Okay, and Val Tiangco will walk us through biomass.

MR. TIANGCO: Good morning, I'm Val Tiangco, I'm the technical lead for the biomass PIER renewables. I'll be presenting the results mainly on the strategic value analysis for biomass.

In the May workshop, on the resources, Brian Jenkins from the California Biomass Collaborative presented this graph in front of you that, what it says is that biomass has abundant, diverse, widespread resources.

In terms of megawatt equivalent, in 2005 estimates, we have about 86 million dry tons of biomass, and if you convert it to megawatts we have over 10,000 megawatt gross capacity. Technically it's over 4,000 megawatts, and the existing capacity for biomass is approximately 1,000 megawatts to date.

So, by 2010 the technical potential is about 6,000 megawatts, and the net technical minus existing is over 5,000 megawatts. By 2017 it's about 8,000 megawatts technical potential, or less than 7,000 net technical potential.

The reason why I'm showing here this graph, the next slides, basically it's the summary of our strategic value analysis. We have a lot of potential from biomass, net technical potential by 2010 -- I'm focusing on 2010, 2017 time frames here simply because that's for the RPS.

By 2010 the net technical potential is over 5,000 megawatts, and by 2017 over 7,000 megawatts, as I said earlier.

The end result of --

COMMISSIONER GEESMAN: Let me make certain I understand what drives the growth in those numbers. It really is a one for one correlation with the size or volume of the waste stream, is it not?

MR. TIANGCO: Yes, the population is one, as you know it can increase the disposal of waste, especially at the MSW stream.

COMMISSIONER GEESMAN: Okay.

MR. TIANGCO: So the projection as discussed in the May, it's based on the projection for the cultural crops, the crop data from the cultural statistics, so those were projected from that base case data.

COMMISSIONER GEESMAN: But most of that growth comes on the municipal solid waste side?

MR. TIANGCO: Municipal solid waste, yes.

COMMISSIONER GEESMAN: And that's pretty closely tied to population growth?

MR. TIANGCO: To population growth, yes.

COMMISSIONER GEESMAN: Okay.

MR. TIANGCO: So, the economic potential. by the way, in this result, for biomass, biomass is not inexpensive, or it's expensive. So we just assume a 25 mile radius within the buffer zone, or within the buss, and calculate the potential megawatts within those 25 mile radius.

We understand that some of the power plants, they take their fuel even up to 75 mile distance. So we are assuming the most economic transportation distance here.

So, by 2010 there is approximately 228 megawatt potential, and by 2017 over 1,000 megawatt potential.

COMMISSIONER GEESMAN: Val, you've opened yourself up for obvious questions. Circles, ovals, ellipses, or did you, did you somewhat customize your areas as well?

MR. TIANGCO: It's mainly circles.

COMMISSIONER GEESMAN: A little less subjective.

MR. TIANGCO: It's just an overview of the resources that we have, mainly from agriculture forestry and municipal solid waste and also the energy conversion pathways and the stream of products that you can get from biomass.

This figure shows the efficiency and the net power output, and the stream of prime movers, energy conversion pathways. Where we are at the moment for the direct combustion using solid fuels, efficiency-wise, is between 15 up to close to 28 percent.

And the 10 to 15 percent of the low output power plants, the high efficiency are the between 20 to 49.9 megawatts, as you know we have two big power plants in the state, Willibrator (sp) and Kornback (sp) Energy, around 50 megawatts, or 49.9 megawatts.

The digesters, you can see, efficiency from 10 percent to close to 30 percent, depending on the prime mover.

We are also showing here some of the biomass projects that are being demonstrated. The gasification project being developed by Community Power Corporation is being funded by the Energy Commission and the National Renewable Energy Lab in this range, around 15 to 17 percent.

The picture technology, using integrated gasification combined cycle, the Carbona-type technology, efficiency over 30 plus percent, 35 percent.

In the white paper that's presented by the California Biomass Collaborative it shows the core strengths of a given power plant. As you increase the COE the levelized cost of electricity increases, depending on the capital cost assumed.

And with the resource potential that we have technically, around 34 million, or 33 to 34 million burn dry tons. Again, CBC developed this cost card that, to date the existing facilities, they use up to five million burned dry tons of fuel.

Meaning to say that, if, this graph doesn't show that if you're using five million burned dry tons you're up close to zero fuel costs, that's what we went on this one. But this is the resource supply curve if you use the approximate 34 million -- technical potential of fuel.

As you can see, the range is up to $40 per burned dry ton if you use forest or timber stand improvements. And the dedicated crops is a future perhaps that may happen in California, but not in the near future.

For the calculation of the levelized cost of electricity we assumed, again like what Elaine alluded to, we used the revenue requirement approach. This shows the assumptions that we used. We used economic life of 20 years and, without reading all the assumptions.

But for the fluidized bed combustor, the base case capital cost that we used is $2,800 per kilowatt, and we projected the cost based from EPRI and Navigant Consulting data up to $2,200 per kilowatt to 2017 time frame.

And the rest just includes the operation and maintenance cost, mainly the fuel cost and non-fuel expenses.

In this capital cost we also include the cost of emissions, and base from the, in order to meet the efficiency standards by 2010. By 2017 based from the EPA calculation on the best available control technologies on emissions it's between $100 to $300 per kilowatt.

And Brian Jenkins with California Biomass Collaborative estimated that if we use SCR to meet the emission levels by 2010 and by 2017, using solid fuels, it may cost $100 to $300 per kilowatt, using the selected catalytic SCR technology. that's for NOX emissions.

COMMISSIONER GEESMAN: Excuse me, are these current dollars or constant dollars?

MR. TIANGCO: This is current dollar. And this shows the assumption for the stoker Boiler, the gasified biomass, integrated gasification combined cycle, and the gas to energy assumptions is also shown in the white paper.

COMMISSIONER GEESMAN: Now, for the fluidized bed or stoker boiler, are there plants of that size -- and I think you had them at 25 megawatts, currently operating with SCR?

MR. TIANGCO: Uh, no. They're, some of them are using SNCR, and also blue gas for circulation.

COMMISSIONER GEESMAN: And operating with those control technologies, have they been able to establish that 85 percent capacity factor?

MR. TIANGCO: Yeah. Some of them they can even run over 90 plus percent capacity factor, but we use 85 percent capacity factor in our assumption.

MR. TIANGCO: This shows the daily waste to capital cost, and also O&M costs. And wastewater to energy capital costs and O&M costs.

This is the result using the biomass fluidized bed, stoker boiler, gasifier, daily waste, landfill gas and wastewater.

Just wanted to let you know that in the daily waste here we assume that the sale of the sludge fertilizer, landfill gas, wastewater, waste assumption here has zero cost. And then for the fluidized bed, stoker boiler, gasifier, assume fuel cost in this table, from 20 to $220 dollars for burned dry ton of fuel costs.

So, as you can see, like looking at 2010 with PTC, fluidized bed over six cents, gasifier close to eight cents by 2010 time frame. However, for daily land fill and wastewater, below four cents per kilowatt hour.

COMMISSIONER GEESMAN: We don't have any gasifiers at that scale, do we?

MR. TIANGCO: No. That's projected cost for gasifiers.

COMMISSIONER GEESMAN: Okay.

MR. TIANGCO: Just to let you know, there is no commercially available gasifier working in the state. But there are gasifiers working in Europe, not in California.

COMMISSIONER GEESMAN: And wit control technology similar to those which we would apply here?

MR. TIANGCO: I know in UK there was one technology within the permit level.

This shows all of the cost price and LCOE comparison. Again, we used the CEC 2003 forecast on wholesale price, and the E3 CPUC wholesale price forecast and the LCOE of combined cycle.

The 2004 market price referent is 6.05 cents per kilowatt hour for baseload and 11.41 cents per kilowatt hour for peaking.

Using a $40 per burned dry ton for fuel, and a 25 megawatt capacity for fluidized bed and even for stoker and gasifier, and one megawatt sizes for landfill gas to energy and wastewater, and a 200 kilowatt system for daily waste to energy, the LCOE -- again I did not show the 2003 forecast here, because it's somewhat obsolete -- so I'm just showing here the combined cycle comparison.

So, as you can see, gasifier may not be cost competitive even beyond 2017 timeframe, but stoker may be cost competitive. You see the landfill, gas, wastewater and dairy is below it, so it could be cost competitive, according to our estimates.

The market price referent, 2004 market price referent, is 6.05 cents per kilowatt hour, so -- it's in this line.

Okay. For the economic potentials, the

biomass resources or fuels that we investigated are the following: we concentrated on looking on the fire threat forest fuels, the landfill gas, dairy waste, wastewater, and we added also urban fuels, especially at the 2017 time frame.

In our economic potential calculation we assumed, as I said earlier, a 25 mile radius for each substation and estimated burned dry ton and megawatt generation.

For forest fire threat areas, a minimum of 120,000 burned dry ton per year was used as a cutoff point. We selected a substation assumed to be in the proximity of installation of a biomass power system.

And for forest fire threat fuels, we assumed fuel costs of $40 per burned dry ton.

You can see here the extreme fire threat areas in the middle of the map. And, looking on the fire threat reduction areas, the shaded portion of the fire threat areas, it's in reverse, the higher --.

And you see the forest fire resources and the hot spots. Without going through the results on the power flow analysis, the benefit ratio if you inject the 393 megawatts, there is actually a benefit to the system.

By the way, Ron will discuss this also for all the biomass resources that we investigated in this study the will be no transmission upgrades. So there is actually a benefit to the system. For every megawatt you install there is a three megawatt reduction on overload on this year 2010 time frame.

By using landfill gas, dairy, wastewater and urban fuel the results of the power flow, by 2010 time frame there is a benefit gas ratio of negative 4.54; by 2017 negative 4.47, so there is a benefit again to the system.

The LCOE, using forest fuels, by 201 time frame. If you compare it to market price referent, assuming that the market price referent for 2010 is 6.05 cents per kilowatt hour, that's a conservative case.

Using forest fuel is not competitive, by this time frame. However, if you use the projected LCOE of combined cycle by 2010, 7.42 cents per kilowatt hour using forest fuel, it may be possible to inject or install power plants using forest fuel around 181 megawatts can be installed using LCOE and combined cycle.

But we made it consistent to be conservative, we used the MPR, assuming that MPR won't change by 2010.

(interruption)

COMMISSIONER GEESMAN: Someone has put their phone on.

MR. TIANGCO: That must be my song, because I like classical music.

By 2010 time frame, using landfill gas, dairy waste and wastewater to energy system, and then using current dollar analysis, and compare the LCOE by 2010 with PTC with market price referent number, you can see that it's cost competitive to inject approximately 228 megawatts of these resources.

From dairy manure to energy, about 21 megawatts. Landfill gas to energy, 162 megawatts. Wastewater, about 45 megawatts. Again, there is a benefit to the system, and if you compare it to MPR it's really cost competitive. More so if you compare it to the LCOE of combined cycle, so it's cost competitive.

COMMISSIONER GEESMAN: You've got a revenue stream, though, associated with the dairy waste -- assumption, I should say.

MR. TIANGCO: Yeah. By the way, the dairy waste, we assume there is a sale of sludge fertilizer, we assume specifically $7 per burned dry ton of that fertilizer material.

COMMISSIONER GEESMAN: Is there good experience with that?

MR. TIANGCO: Yeah, I think we reference it in our paper that for one of the facilities close to Chico, the Longovor (sp) facility, they're selling sludge, -- material.

For forest fire fuels, by 2017 time frame, you can see here, when you compare the LCOE with PTC to combined cycle, there is a possibility that you can inject approximately 320 megawatt. The only county, in terms of resources examined, is Tehama, the LCOE is over 12 cents per kilowatt hour. So it's not cost competitive.

Again, for landfill gas, dairy waste, wastewater and urban fuel, it's cost competitive when you compare it with LCOE of combined cycle. So there's a possibility that you can inject 27 megawatts from dairy manure, 199 megawatts from landfill gas, 58 megawatts from wastewater, and urban fuels about 361 megawatts. This urban fuel is mainly construction debris from the MSW stream.

COMMISSIONER GEESMAN: Just so I understand, you're assuming that 2017, for landfill gas, there would be almost 500 one megawatt facilities on landfills that currently do not have facilities, or --?

MR. TIANGCO: Yeah, currently do not have facilities, and it's most likely good potential to take that wasted energy.

COMMISSIONER GEESMAN: On an economic basis?

MR. TIANGCO: On an economic basis.

COMMISSIONER GEESMAN: With controlled technology capable of meeting California standards?

MR. TIANGCO: Yeah, we hopefully can meet that 2007 standard.

COMMISSIONER GEESMAN: Okay.

COMMISSIONER BOYD: Now that you've said that, and I was saving this for kind of the end of the day in solicitation to all of those who either might speak or present written testimony, we need to know what kind of hurdles there are out there relative to some of this.

Hurdles and issues that need to be addressed. And I know in this area this is a big hurdle, this is not a little hurdle. It's not just, well, presuming we can meet that standard. From all I hear, from a lot of you out there, that's a very significant hurdle.

And there are others associated here. And therefore we need to know them so we can address them, so --.

MR. TIANGCO: Yeah, thank you, Commissioner Boyd, for saying that. That's really a big issue for biomass, especially the NOX, to meet the NOX emission level, the 2007 standard.

We know for DG the NOX standard is .07 pounds per megawatt hour. Only fuel cell and I think some microturbines can meet that level.

COMMISSIONER BOYD: Right. And just another commercial, the biomass, the Bioenergy Working Group, the Biomass Collaborative, and this agency in its Integrated Energy Policy Report, need to know, to document these kinds of hurdles.

So we can make them policy issues that get pursued by policy folks later on. So, a good opportunity to make that point. Thanks.

MR. TIANGCO: I guess that's the end of my slides. The limitations on the SVA analysis on the biomass fuels, we did not evaluate the orchard prunings and some food processing waste and the other waste material.

We basically evaluated the fuels that pose danger to our society, the catastrophic white virus, you know, is a big thing in the state. So we need to help solve the problem. We spent over a billion dollars this year just to suppress wildfires. So we analyzed forest clearings and forest land fires.

And then we analyzed the low hanging fruit, because, as you know, biomass is very expensive to gather and collect, process, etc. So --.

MR. SIMONS: Thanks, Val. And we'll shift and start talking about solar. The information on solar really builds off the solar white paper delivered in May. So, again, we only considered concentrating solar and flat plate PV technologies, which is a caveat there, there are other technologies out there, but this is what we looked at. These are the most common technologies.

The approach really had four basic steps. Again, going back to what I said earlier, we had to look at performance and cost projections out to 2017, looked at hot spots --.

By the way, we keep talking about hot spots. Those are congested, capacity strained areas within the grid. And they're not necessarily bad things, you know, in some cases they're opportunities where you can inject generation or re-conduct or do an upgrade, so hot spots aren't necessarily, we call them hot spots which suggest just problem areas -- yes, they do pose problems, but they're also opportunities.

So, again, we co-located resources where possible to try to go ahead and take advantage of an opportunity to inject megawatts where we could get a benefit. And again we used the combination of power flow, resource assessments, and GIS tools.

Conclusions for the concentrating solar technologies. What we found is that, again, we have over 150,000 megawatts of concentrating solar that's available in the state economically. If we look at a minimum solar resource of seven kilowatt hours per meter square per day.

But that shrinks down to about 4,500 megawatts if we then up the minimum solar resource to about eight kilowatt hours per meter squared per day.

Just as a reference point, the Luz facilities down in the Tehachapi, down in the desert area, generally have that kind of solar resource, eight kilowatt hours per meter squared per day. So it's a high quality solar resource, so that's really our primary emphasis.

We also found that, again based on some of the information I'll talk about in a second, that where you had high insulation, and where you employed thermal storage for natural gas hybridization, then CSP could feasibly be cost competitive in the RFP solicitations, based on the MPR prices.

And when you do that, what we find is that by 2010 we'll have approximately 1,100 megawatts of economic CSP systems that would be located very close to the substations that could in fact benefit by having generation installed, and they would not have to pay for new transmission capacity.

Again, that doesn't mean that we won't see additional or other CSP be developed. But in accordance with the methodology that we developed and followed then we'd get about 1,100 megawatts.

And if we installed or injected that 1,100 megawatts we would get a system benefit in terms of reliability of three to one, so for every megawatt installed we'd get an actual net system reliability benefit of three megawatts.

And again, based on some of the cost and performance trends, we would see that 1,100 megawatts having a generation capital investment of close to $3 billion.

On the PV side, under business as usual conditions, otherwise gradual or incremental cost reductions in PV, nothing in terms of a breakthrough, that we would see the levelized cost values close to 20 cents a kilowatt hour by 2010, and then begin to fall down to below or close to ten cents by 2020.

And for commercial building systems using PV we would expect to see a very similar type of trend.

So we know that PV is cost competitive in certain arenas. It's cost competitive when you look at tier grades, when you look at time of use rates, or in the case of some companies in California where they've established special finance arrangements that are longer term and capture non-energy benefits, for example, a roof life for a grid-connected PV system.

So PV can, in fact, under those situations, be cost competitive. Nonetheless, for the near term, employing of PV is going to continue to rely on public incentives, primarily the million solar roofs initiative.

And based on some projections that were made for the million solar roofs we expect to see 500 megawatts of PV employed by 2010. And then over 2,000 megawatts -- and I understand the number may be closer to 3,000 megawatts, by 2017.

So when we provided those numbers to Ron Davis and he looked at PV on an aggregated DG basis, we would expect to see a two to one benefit. So again, we would get 1,000 megawatts of benefit for installing 500 megawatts of PV.

So how did we get to these findings. Again, we looked at trough and power tower systems on concentrating solar. We also looked at dish sterling systems, but I won't cover that here because in fact they weren't able to compete at all in the 2010 time frame, under the cost and performance trends that we have.

Now that may not be the case, but under

our methodology they just didn't make it.

So what do we see here? These cost and performance trends came out of an independent study by Sargent Lundy, who in 2003 were asked by DOE and NREL to come in and make an independent assessment of concentrated solar power technologies.

And the Sargent Lundy study found that in fact these technologies could move forward without breakthroughs in technology. And in fact incremental types of improvements could make these systems cost competitive under their scenarios in the near term and the longer term.

And so when you look at the trough analysis -- by the way, Sargent Lundy looked at the Sunlab cases and made an independent assessment. But when you look at these cases, what they really came up with is by a 2010 time frame we would expect to see installed cost of a trough system of around $2,500 a kilowatt.

On our revenue requirement model, these are the inputs that we used to come out with the levelized cost numbers that we have here. And so if you're using a $2,500 per kilowatt dollar installed cost we end up in a 2010 time frame with an LCOE value of around seven cents a kilowatt hour, it doesn't matter if there's a PTC or no PTC, it's around seven cents.

And so here is what the numbers look like visually displayed. And you can see again, on the chart, that this is the MPR 2004. Now obviously the MPR is not going to stay flat, it'll change over time as gas prices for example go up, and MPR values go up, they'll track it.

That's the baseload MPR. This is the peaking MPR, about 11 cents, this is down about six cents. And what we find is that, again, on a baseload MPR value that the CSP technologies don't necessarily compete.

But they do compete on peaking. And that's a very interesting phenomena because in fact, one of the benefits potentially of solar is that it does track peak.

And this is a chart from Solargenix. And in fact, if you look at the solar resource -- this is the demand, okay, and you look at solar resources from Harper Lake, that's Harper Lake in the SMUD area, and you can, again, there's no surprise here, solar does in fact track peak load.

Now when you add hybridization or

thermal storage capability then in fact you can round that out. So you could get a situation where a solar facility, a concentrating solar facility, could provide peaking generation to the utility.

So we know that, in this particular case, concentrating systems with thermal storage could probably qualify for the MPR peaking.

I'm going to switch a little now and talk about power tower. Again, Sargent Lundy did an independent analysis of tower technology. What they found, again, was they were looking at, addition of solar thermal.

And what you get is a huge increase in the capacity factor from solar too, which was a facility established down in the mid-1990's down in the desert, going up to from 19 percent capacity factor all the way up to 70 percent capacity factor. But that requires 13 hours storage.

And so if you take those numbers for their capital costs in, and you run it through the revenue requirement model, then what you come up with is -- well, let me back up here.

So these are actually our cost trends.

So, again, you can see that with this kind of capacity factor what you end up with is an increase initially in the capital investment but when you go to the revenue side of it you end up with a much lower levelized cost of electricity generation.

In fact, the tower technology has a lower LCOE than the trough.

Now, the methodology applied by Sargent Lundy was reviewed by the National Research Council, and they generally found the results to be very credible. The one area that they had problems with the Sargent Lundy approach were on the assumptions regarding deployment of the technology, and particularly the tower technology.

In order to get this kind of a cost reduction there had to be a significant amount of tower facilities being produced. And so, instead of using the tower cost we went ahead and used the trough cost in looking at CSP throughout California.

Now, similar to what Dora did, we had a map where we had solar insulation values on a ten meter grid basis, supplied by NREL to us. And what we is we looked at what would be the solar resources that would meet certain minimum criteria, in some cases six to seven kilowatt hours per square meter per day, and in some cases beyond that.

And so, as you see, I talked about at seven kilowatt hour per meter squared per day you have 150,000 megawatts of potential. So that's really what we see here, is that kind of capacity potential.

And again, based on the capacity factors that Sargent Lundy came up with, this is the kind of energy delivery numbers that you'd expect to see.

Nonetheless, when you go to the much better solar resource areas in the state, which are really very limited in the land area available in California, it shrinks down to about 4,500 megawatts.

So what we wanted to do then is begin to look at what would be the intersection between the hot spots and that good solar resource.

And so we initially found out that we had about 1,200 megawatts that would intersect the WTLR's, but only 1,100 megawatts that intersected and were at that very high solar resource.

So again, our economic CSP potential for 2010 is 1,100 megawatts. And again, when we took and Ron Davis injected that into the system, what we saw was about a three to one benefit.

Okay, so let's shift from concentrating solar to photovoltaics. And we had really two different cost trends, as well as our own that we were looking at.

Navigant has independently looked at what is happening with wafer technologies going out through 2010. And what you'd expect to see here is the installed price is dropping incrementally.

And in fact we really don't know what's going to happen with PV prices, because of the very fact there's a huge demand in Europe and Japan that's sucking up all of the modules. So we could see an increase in PV prices even though the cost of manufacturing PV systems is going down.

And I apologize for this chart, I didn't realize just how poor the visual is on this. But we're seeing an independent assessment from NREL that shows the same thing. There's no big surprise here.

Short of a breakthrough in photovoltaic

technology there's going to be an incremental cost reduction.

And so when you plot those out what you see here is that PV system costs drop, gradually, going out to 2018. And by the 2010 time frame, really unless we have some special circumstances, the costs are going to be up at around 15 all the way up through 20 cents a kilowatt hour.

So we know that there are special circumstances though in which PV is cost competitive. It's under tiered retail rates, time of use rates, or special financing.

We also looked at PV on commercial buildings. And again this is based on Navigant and DOE/NREL cost projections. And again, you see very similar results, a very gradual cost reduction, but again no surprise that the levelized cost is above 20 cents a kilowatt hour.

Now, I mentioned that the way we expect to see PV systems deployed by 2010 is primarily through the million solar roofs initiative, and we assumed that it would largely be, at the time we were doing this, the residential sector.

It doesn't necessarily have to be defined to that area, and it will not be confined to that. But one of the things that we did was, we said well, if you wanted to get the best system impact by installing PV, let's look at first installing it in the highest growth areas.

And there was some logic behind that, because the highest growth area's tend in California to also have a large amount of demand. They tend to be located in areas that there's a hot climate.

And we said well, okay, there are also congestion problems in those areas. So we had Department of Forestry provide us with a listing of what are the highest housing growth areas in the state.

And then we took and injected the PV megawatts, or Ron did anyway, on an aggregated basis into those areas. And this map is very busy, but what you see down here is in southern California, in the Bay Area portion of the state, those are the highest housing growth areas.

And what we end up with is if we inject that 500 megawatts into those areas we end up with about 1,000 megawatts of system benefit.

And that's all I really have to say about solar, unless there are any questions.

We were intending to take a ten minute break for people to go ahead and grab handouts, use the facilities if need be, and then in ten minutes we'll start up with Ron Davis' presentation.

(Off the record.)

MR. DAVIS: We heard in the sessions before this one all the analysis that was done on each individual renewable technology and each individual location.

One of the things it becomes is what do you do after that, and how do you look at meeting the 20 percent or meeting the target by integrating these resources together? And then what happens when you start integrating them together, what happens to the transmission system?

So one of the goals that we had, our objectives we had, is can we get there by 2010, can we get to the 20 percent penetration, can we do it with in area resources, and can we do it without building a lot of transmission instead of trying to find some areas where we say oh, yeah, this is a good spot but it's going to take us five to ten years to build the transmission.

We tried to look at are there areas

where we can expand and put into renewables and be able to see how close we can come to the 20 percent?

I know I've had conversations with, you know, Vulcan Power, and Allen Allman fromm over on the Dipse (sp) Valley, the Nevada side, and we've been talking about transmission and how to connect, and the value of the out of state and how they fit into it.

But this part of the analysis I'm going to be talking about today is really looking at only in the in area.

I'd like to thank all the people that have participated in helping provide us all the data we've done in our analysis we've done, and benchmarking, and doing the analysis, so I'd like to thank everybody that participated as far as within the Energy Commission and also Prad for everything and coordinating and everything that he's been doing for us.

Part of the SVA methodology is to assess renewable technology resources with the potential of meeting our goals, identify the focus areas where additional studies need be completed -- and I'll talk about that a little bit later -- the economics and the time frame -- you heard about the economics this morning, so I'm not going to go into that.

Evaluate the points of interconnection and some of the issues dealing with those. I'm not going to get in to the environmental and the non-energy public benefits at this time. Those are going to be, I think those are in some of the papers.

And what we wanted to look at is solutions that can defer transmission upgrades or reduce transmission congestion and improve reliability by using renewables at strategic locations.

You heard a lot in detail, so I'm not going to spend a lot of time over this, but just to give you a quick review. If these were places where, according to the power flows in 2017, these are the areas where it would be economical to look at injecting transmission or injecting renewables into it.

The red areas are the areas where we'd really like to inject new generation into, the yellow areas are good areas, and blue areas are areas that need really a lot of transmission upgrades in order to do any development there.

Now, before anybody gets excited about the red and blue and how dark the red is, we didn't do any upgrades to the system. So we just took 2010 and expanded it out to 2017, but didn't do any solutions. So the low growth and no additional transmission and generation causes the problem.

If I did a solution then you wouldn't be able to see the benefits putting renewables at specific locations, and I don't want the IOU's or anybody else to get real excited, because we didn't do any solutions.

Okay, quickly. We looked at the geothermal, and we looked at the locations where geothermal, the potential for geothermal. And I drew two circles, one was a 10 mile and one was a 25 mile circle.

And what we did is say that with geothermal that's out there where are the hot spots, where on the transmission lines congestion areas can I connect to to provide a benefit.

And so this is how we looked at whether or not we could find anything and build in geothermal that was next to a transmission congestion or a hot spot area. So those are the triangles, is where we would want to try to interconnect to.

If we look at the wind, that's what you saw earlier, we looked at these areas where there'd be a wind impact and a wind benefit, and we've been through all that this morning and talked about. But, you know, we kind of looked at all those spots.

George talked about the flat plate, the residential. We looked at, when we first started the screening, as he showed, we looked at 57 counties, 380 housing development sites we looked at.

Solar, we did the same thing on solar. We looked at where solar development was and where our transmission hot spots were and tried to look at the relationship of where we could put those in.

Biomass. One of the things on the fire threat. Although it wasn't economical in 2010, what we tried to do was look at -- California has a lot of fire threats, and a lot of forest fires. So if we were to do some forest thinning, where would we look at, and can we provide a benefit for the transmission system by locating them at ceratin areas.

And so we really concentrated in this area up through here, which is 120,000 burned dry tons a year, of is there any places where we could install them up there. And then we looked at areas that really had the high concentrations within those areas and seeing if we had any spots within them.

Now, how did we pick where we located them for doing transmission studies? so that PG&E doesn't get really excited on the buss side pick, I took a compass -- and these are true circles -- I took a compass, laid out the map that I got from CDF, and I tried to do circles around a 25 mile radius and I tried to minimize the overlap.

And so if I did the whole area can I find areas that, if we were to be able to haul the forest material say, within a 25 mile radius, could we find locations that we could haul into one central point and be able to burn it.

Now, this is 20 megawatts over a 30 year time. Would we take 30 years to do a forest thing within this 25 mile circle? Well, if we only took ten years then this megawatt goes up quite a bit.

So, nothing scientific, but I wanted to see if I could locate some of the stuff within the area, is there a benefit to the system, and can I minimize my transmission and locate something within there that provides a benefit?

And here's just another example. Here again, that plus may move to this one or this one, we didn't look at roads or go out and look at the size or where that was at, it might be on the side of a hill for, you know, for all we know.

But I wanted just to try and get a quick look at what those are and what those impacts are, and so we did really true circles.

Now, what is the methodology? The shaded area is actually what we did this year, and this analysis, but it isn't exactly how we would do it, and most likely if I was to start all over again and start from scratch I probably would do it a little differently.

We didn't, as I said before, we didn't include any of the out of state. Our goal on this page was to look at can we do it with instate renewables, but out of state's really got to be put into the potential and participating in this.

So if we were to look at what we

accomplished, we started at assessing the renewables in area, looking at potential, and then doing the LCOE's, and then running a lot of transmission analysis and looking at the cost benefits, least cost bet fit kind of approach.

And we really dealt within this circle right here of looking at how we'd meet it. Ideally we would want to get the utilities involved from the very beginning. We need to know from the utilities what do they really need from within their service territory.

In looking at their load, do they need more baseload, do they need more wind, or intermediate peaking? And I think we have to do more on looking at what the utilities really need for a resource mix in order to come up with what makes sense if you want to do a least cost bet fit analysis.

You have to look at what existing has already been done, what' sunder contract by the utilities. That's one of the issues that we were having a hard time getting a handle on was what was under contract.

Because a lot of it is being negotiated, it's confidential. So we would have a hard time getting a good, firm handle. So our megawatts may be off because the utilities may have done contracts that we don't have included here that would change our mix if we were to add them in there.

And just to get more utility or more service area, control area participation in doing this. And then go through and allocate the resources to try to meet the service area, what resources are within the utility to minimize transmission and to put as much renewables as close to the load center as is possible to keep costs down and to look at those.

And then to look at what areas we would bring in from the other control areas, service areas, to help meet that load. And then also we have to consider the out of state resources into this.

So it's really a lot more than what we did on our analysis, so that's why, when we go through this we're not trying to say the approach we took here is the final and the way you go, but we look at this as really being fully integrated with all the agencies -- the PUC, the ISO, the Energy Commission and the utilities, to really make this work.

For our analysis, because we were only looking at the renewables that were close to transmission areas that we could see if we could fit into easily to meet the 2010 with as little transmission, we looked at the geothermal, the biomass, the forestry, natural gas, urban gas, and dairy manure that we talked about. We looked at high wind in 2017 and low and high wind in 2017, and then we looked at solar.

Ideally, as we said before, we want to sort by utility, by renewable type, transmission ratio and resource needs.

Now, what was our target? If we looked at what the utility's load forecasts were and what's really kind of being planned, we'd come over and we'd say that in 2004 the actual total utility projected load was 27,191 -- I'm sorry, that's how much renewables would be needed in 2004.

When we project that to 2010 the number comes to be 56,160. The difference between the 27 and the 56 is the number that we looked to try to target for 2010, which is about 28,000, is what we would try to see if we could fit in to meet with area resources.

Now, if we did that to 2010 and then we went out to 2017 the number is 61,000, so we're only adding about four or five thousand gigs between 2010 and 2017, but we're putting approximately 28,000 in by 2010. So that was the target that we were going by.

And we did try to incorporate what the utilities had done up unto that point, from 2001 to 2004. But what we don't know is what things they have that they've already contracted or have in between that period.

Before I get into -- I want to talk a little bit about this impact ratio, because I don't want anybody to get real excited about this number.

The impact ratio as we go through and calculate the WTLR's and we calculate a statewide transmission reliability we're really looking at a relative measure, it's an index to compare alternatives compared to a base case.

So I don't want people getting excited about the magnitude of the number of what that number is. It's simply a measure of the reliability of the system.

So if we were to take our 2010 base case, and we run a steady state and we run an N-1 and we come up with a transmission reliability index. ?Then I take a scenario where I put in some renewables and then I run that number again. Hopefully I should get an improvement in my transmission ratio.

So if I take a difference I get an improvement in my transmission reliability number. Then if I take that difference that gives me my impact ratio. If I divide that by the number of megawatts I've put in that gives me my ratio.

So it allows me to compare different alternatives, to have different megawatts at different locations, but if I study it on a statewide basis I can come up with a relative index that I can compare something in southern California with northern California as to their transmission impacts to the system.

So that when I do a statewide I'm always looking back to the referents and I'm always comparing resources, so it allows me to do an equal comparison.

Now we were looking at thermal ratings of the transmission equipment, the transformers and the transmission lines. We also, when we were doing this, we did look at low voltage and the VAR flows but we didn't use that in our analysis of an impact ratios, but we did consider all those because there would be some cases where resources could be improvement to the low voltage or VAR's or other areas where they may create more of a problem in those depending on where they were.

And then the impact ratios will change between spring and winter and what scenarios we'll run. And also they could change with hydro conditions depending on how the flows are in the system as we're doing it.

So there's a lot of things and considerations that you use in your assumptions to do the impact ratios.

But given that, if we were to take the analysis that was done earlier this morning and we did transmission analysis by -- well, one of the things I want to get in to here before I get into this -- I started combining everything that was talked about this morning.

So if I start and make a list of all the things that were studied in solar and geothermal and I start putting it all together, and I look at the megawatts, I look at where it's at, I look at my 2010, 2017 impact ratios, and then I look at the LCOE that was used in the morning sessions for calculating what we'd be comparing against, now I can start and look at these resources and these locations that we've picked and I can start to eliminate those that either do not meet the impact ratio or do not meet the LCOE, they're not competitive.

Now when we say here again, when George was talking, we say not competitive, we're using standard costs and we're using specifics where we can get it. But we're also using an MPR number to compare to.

Now when we get into the actuals we get into more details, those could change.

Now here I used current dollars, I had PTC but no transmission. The assumption was that we were trying to build things that didn't require a lot of major transmission, except for the Tehachapi and the Imperial.

And we included those down here because of the studies and the things that are being developed. We did include them in this analysis that we had.

So when I look here at my list and I look at concentrated solar, high wind, and low wind, we can see that none of them were eliminated on this sheet, according to some of our analysis.

Well, low wind should have been eliminated, I don't know what happened to my drawing. Low wind was not economical in the 2010 time period, so somehow that didn't go, but they were over in the 2017.

And I'll clarify on low wind. Low wind was distributed low wind, and what we were looking at was instead of putting low wind in where we had high wind sites, what Dora and I were trying to look at was if we could find low wind sites close to load centers, that we could put low wind generation in and provide a benefit to the system instead of adding it to where the high wind sites were already -- and those were large megawatts for the high wind, like Tehachapi -- instead of looking at those could we find individual low wind sites that could be distributed.

And if we could get some encouragement from the developers and the utilities to build close to those, could they provide a benefit to the system.

And interesting that the benefit ratio didn't come out as much as I'd hoped, the numbers only come out to be -.3. We only picked a selected number of sites, and a lot of them, actually all of them were in the PG&E area that we picked.

And they were economical in 2017, but their impact ratios were pretty low, but at least they were negative. And it does show that we can do some things by putting in some distributed low wind that would be low wind only, and provide a benefit to the system.

But you can see some of our numbers here range from -1.4 -- and here again you see the Tehachapi. When I did some corrections for some additional transmission upgrades it came out to be .008, so our number dropped from the positive 1.4 down to the .008 because I did some additional transmission expansion to get it closer to the load center.

So let's say, we could get pretty close to putting 1,200 megawatts, we can show a benefit ratio that doesn't hurt us. It doesn't provide a big benefit because it's located so far away, but it does provide a benefit to the system.

If I come over here to look at the biomass forestry, you see they all don't make it in 2010. You see biomass, the dairy manure has a really good impact ratio, because those are going to be located in areas where we could connect to the transmission system.

The forestry really comes into play in 2010, and if we look at landfill gas it has a really good ratio, and wastewater treatment has a good ratio. They're the same because of a couple of things.

When I picked them i aggregated them together into one location, so when I was drawing those I didn't do a separate theory on manure, and I didn't do a separate landfill gas. But when we drew our surplus and drew our stuff we tried to aggregate into one substation. So I tried to do it under one study.

If you look at the geothermal you see that some, the Superstition Mountain has a really good one, but you see the megawatts aren't very big. So would we really be able to go and do anything down in that area of the megawatts being so small.

And we did have some other ones down in

the Imperial Valley area that were both cost-effective and really good impact ratios. And then you see a lot of the other ones over here were eliminated because their costs were too high.

And so we went through and we eliminated those where either the LCOE's were too high or their impact ratios were a positive.

If I was to look at PG&E's area, you see that all of them got eliminated except for the sulphur bank area up towards the geysers, at 43 megawatts it's economical.

The rest of them in 2010 were the development of the geysers and the ones that were in the area over there, Calistoga and the other ones, were not cost-effective or their LCOE numbers or the impact ratios were not good.

So we eliminated all those from our list of analysis that we would do. Do, given that we would eliminate the ones that didn't make it because the impact ratios of the LCOE's, how close were we able to come?

So what we did is we took our transmission data set and we started to add the renewables that were cost-effective. We began adding them in to our system and we started doing transmission analysis.

One thing I want to make before we go along, if I take these impact ratios and all the ones that were good, and I weighed them by their megawatts, and you see the range of these go from about zero up to almost -15, if I average all those together it says on this chart, the table, that my average when I get all done should be -1.65.

So it says if I was to put all these in that were in there and I just add up their individual ratios and weighed them then I should come up with almost a two to one benefit.

So it says if I inject 4,000 megawatts onto the system it's the equivalent to putting in 8,000 when I do my reliability index. And I want you to remember that number, because when we start doing integration it's going to change.

So I started taking my numbers and I started adding in my resources to try to meet my target of 20 percent. And our target was 28,969, using -- now Salton Sea was limited to a megawatt level, and so was Tehachapi, based on talking to the Tehachapi and the Imperial Working Group of how much could be put in within the transmission and within the lead times to build transmission and to build the power plants.

So, Salton Sea we limited to 800 megawatts, and Tehachapi we limited to 900 megawatts, and then we started putting in these other resources.

We installed 6,000 megawatts of renewables. We got to 24,575 megawatt hours. We were 4 million -- so we got the 85 percent. And that's without any out of state. That's without trying to look at building any extensive transmission outside of Salton Sea or the Imperial Valley area, we were able to get to 85 percent of the target.

COMMISSIONER GEESMAN: I thought Dora had told us the capacity factor number she was using for wind was around 25 percent?

MR. DAVIS: It was 25 percent for low wind and then it was 37 for high wind.

COMMISSIONER GEESMAN: Okay.

MR. DAVIS: So we did include, as you'll notice up in the Medicine Lake area, they're trying to build that out to 175 megawatts, so --. This was the connected, installed megawatts that we were able to put in in able to get to the only

85 percent.

And here again we weren't trying to force it in, we were trying to do resources that were close to hot spots.

The average capacity factor of the resources we were trying to put in was 46 and 1/2 percent. So some of the things on the reasons why we didn't meet 100 was we didn't try to incorporate any of the new contracts the utilities have done and we didn't include any of the out of state resources.

This map kind of gives you an area of where these resources are located. You see the majority are going to be in southern California, a lot around the San Francisco Bay Area. So these were the areas that we picked where we installed all the geothermals, all the renewables.

If I was to look at my mix by technology type you see that about 20 percent of the capacity comes from geothermal and about 39 percent of the energy.

If we look at high wind it's about 50 percent of the capacity and 40 percent of the energy was calculated for the mix.

Another way to look at it is if I looked at a pie chart, this kind of gives you a breakdown of the capacity mix of the renewables that we installed in 2010.

So you see four percent came from the biomass in 2010.

If I was to look at the energy, here's the breakdown if I was to look at the distribution in 2010.

Now, let me go back to this one. As I said, in 2010, if I was to do a weighted average of the individuals, we had a -1.65 benefit ratio, which says that they were really good.

As I started adding these in and I started doing transmission analysis and load flow analysis and I put in all this new renewable our impact ratio actually increased to -.224. So we dropped from a calculated number of 1.65 down to a number of .224.

The difference came about because as we started adding these we started having transmission overloads. So we started loading up the system in 2010, even though we were trying to locate them near a load source and close to a hot spot, when we started injecting all these and we started accumulating them up, because they were sharing transmission lines ultimately our impact ratio actually got worse.

So we dropped down to a .224, which says individually when you run these they all look good, but when you start integrating them on a statewide basis we begin to have problems.

So you can get an idea, if we just started throwing these up and just started not picking strategic locations we could run into more transmission problems which would be more lead times, so not only do we have to look at what transmission lines are required to connect the resource, but we have to look at the impact on a statewide basis on to the grid.

We upgraded, I think in 2010 we I believe upgraded ten lines, and we took the impact ratio up from a .2 to a .7. So we were able to go in and just do some quick picking a few lines. We picked ten lines out of the whole state, we upgraded those, and we were able to recapture back to a .7 compared to a -1.65 that we had calculated.

So there are lines that are going to have to be upgraded. And of those four were 500 KV lines and six were 230 KV lines. So that gives you an idea of the voltage of the transmission lines that were being impacted as we started to add these.

Now if we replace these with renewables, would we end up having to replace transmission lines? The answer is yes. Would we have to do more because we're trying to strategically locate these? Probably we would have to do a little bit more.

Now if I move that to 2017 and I carry over the amount I wasn't able to meet in 2010 and then the amount that I had to do in 2017, and I'm again adding those resources that are now economical in 2017 -- we added another 400 megawatts to Salton Sea, we added in some of the biomass, we brought in the low wind.

And so we brought those in and we started analyzing those, and we continued to put in concentrated solar and residential solar. And we're actually over. I didn't try to do a perfect fit because I was trying to match capacity factor, but in 2017 we don't have any problems, because a lot of the other resources are becoming economical, they're more becoming available.

And you can see, the average capacity

factor was 55.6. It went up quite a bit because we started adding a lot more geothermal. And we added a lot more geothermal in there and the biomass, which has a high capacity factor, so we were able to increase the overall capacity factor that's in there.

We met the 100 percent. And we didn't max out all the low wind sites, we didn't max out the Tehachapi or the coal biomass, and we still did not have to do any out of state resources.

If I was to look at my mix for 2017, you can see that 21 percent of the capacity was geothermal, and wind came in at 42 percent. So we were still doing a lot more wind capacity.

And these were the locations where we picked to install the renewables for, this would be the total of 2010 and 2017. It kind of gives you an idea of how the distribution was across the state as far as what we put in.

This would be the capacity mix for 2017, to give you a breakdown of what these look like.

And this would be the energy. Now you can see that low and high wind is going to be 33 percent of the energy that's being generated by 2017 under this scenario, and geothermal makes up about 38 percent of the energy in the analysis we did.

What we've come to a conclusion is yes, we can meet the 20 percent by using in-area resources, and we can but not by 2010 if we only look at those resources that require a little transmission upgrades and try to minimize transmission upgrades.

And what our goal was was to try to help improve the grid and the transmission reliability by building them closer to the load centers.

By comparison, when we put in the whole 8,000 megawatts I believe it was of renewables, our impact ratios dropped to .9. When we upgraded, I think in this case we upgraded 13 lines, our impact ratio increased to -1.25.

So by installing 8,000 megawatts of renewables at at strategic location and upgrading some 13 lines we were able to get an impact ratio of -1.5, which is really good for putting in renewables and providing a benefit to the transmission system.

Some of the things that we need to do is for seasonal transmission power flows, one of the things is how can we incorporate this in. The utilities and the developers, can this be a benefit to you to help select sites and to evaluate sites and prioritize sites?

We need to bring in power simulation, we need to do production cost modeling to look at some of these seasonal benefits.

And we need to integrate this to make it more user-friendly. One of the ideas that we had from the start was for this to be installed at the Commission and to have people come in and actually run it here and be able to run it and use it, so --.

Because people don't want to always give out their confidential information, can they come and have a place where they can look at their sites and see what the impacts are and be able to do some analysis and see that this is a value.

As we talked before, PG&E is going to be working with us to try to fine-tune this and to be able to look at it and be able to see what's it's value and how does it work and so we're excited about being able to work with them on it.

We need to expand the number of sites. We did only a limited number because of the time, and be able to demonstrate that this can work.

And we need to do more with the out of state utilities. And some of the out of state transmission lines.

In talking with PG&E and George from Edison, one of the things is, when we have all this out of state coming in on all these transmission lines what's the impact on the total California system and where should they terminate, and what impact do they have, and how do they interface with what we want to do internally?

That's my, I went kind of quick, but I wanted to give you an idea of how we went about doing it. We did it by picking and prioritizing the resources, doing a lot of transmission low flows, looking at their impact ratios, and being able to see if we can do it with a minimum amount of transmission upgrades.

COMMISSIONER GEESMAN: Ron, what did you change regarding load from today to 2010 to 2017?

MR. DAVIS: Okay. We matched the low growth that was the forecast by the Energy Commission, that they had forecasted for low growth out in to 2010 and 2017.

We initially got the data sets from the utilities, and they've been very cooperative and very nice to work with and very friendly and provided a lot of good information.

So we took their data sets that they provided, and then we worked with the electric energy supply office, and we looked at the low forecasts that were being developed by the state.

And then working with Don Kondolean's area we looked at retirements, additions, transmission upgrades, power plant additions, power plant retirements, looking at what the ISO had projected for retirements.

And so came up with a data set that matched, that came close to the forecast by the Energy Commission, and matched with what was being projected and forecasted as to what would be new retirements and new additions.

COMMISSIONER GEESMAN: Thank you.

MR. DAVIS: Another comment is that we're currently working with the utilities right now on updating our databases, because it's, to get as current as we can. And we've contacted all of them, and again we're working with them to get an up to date database developed.

Any other questions? Oh, and there are more copies, and I hope they're out there by now, of the copies. And I apologize, somehow it didn't get on the webcast. I set it up about two days ago, and I apologize that the copies did not get made, but the Powerpoint should be out on the website and I apologize for any confusion that happened on that. But copies should be out there.

MS. NAKAFUJI: I just wanted to clarify one point. I think there's some confusion maybe on the capacity factor that was used, what you saw in Ron's chart, and also the availability of the resource that we used during the summer analysis.

So, just to clarify, we did account for the summer megawatts of wind in the analysis, and that's the 25 percent. But the capacity factor of that resource is at 37 percent of the high winds and 25 percent of the low winds. So I just wanted to clarify that.

There's a lot of percentages, so --. Oh, and copies of Rob's presentation are out there now. And there's also a sign-in sheet for people who haven't signed in on that.

MR. SIMONS: I was just going to jump back to the -- oh, I'm sorry.

COMMISSIONER GEESMAN: Don, did you have a question? Come on up to the microphone.

MR. SMITH: My name is Don Smith, and I'm -- it's too hard to explain, I has something to do with working for the Public Utilities Commission, but I'm not sure what department I'm in at this moment.

And my question is about the figure of merit you developed, the impact ratio. Now, is that adequately explained in the report someplace, or is it possible to explain it in 25 words or fewer?

First I thought it was sort of an, in effect, a sort of negative version of effective load-carrying capability in a power plant, but then when I heard values over one I eliminated that possibility.

But, basically, what does your impact ratio of say 1.2 or -1.2 actually mean as far as reliability, and also what's your measure of system reliability. Is it lots of load probability, or --?

MR. DAVIS: Okay, sure, good question. There's some task reports, I don't know if they give that on the website, but we'd be glad to give you other information as you need it.

But basically what we do is, once we

have a dataset, we run our, say an N-1 contingency analysis. And then we take the values of the overloads that occur on there, and looking at the numbers of the violations, the voltage of the line that's overloaded, and the number of occurrences, we calculated a weighted transmission overload. We calculated an aggregated megawatt contingency overload.

And that says, on a statewide basis, if I was to look at my overloads, and I was able to do some things where I want to weight those and come up with a total value, I come up with a certain value.

An I'll use an example, it comes out to be 10,000. Now, that doesn't say how many megawatts you have to install, actual megawatts. It says if I was to look at my overloads and I was to weigh them and the number of occurrences, it gives me a relative value of the reliability of the system.

Then, if I run a scenario where I run something else, let's say I put in some renewables and I get a value of 9,000. So, if I only put in 500 megawatts and I got a 1,000 megawatt deduction in my weighted value then that says I was able to improve my statewide contingency overload by 1,000 megawatts, and I installed 500 to get to it.

So that says it's a two to one benefit. So if I can put a generation at a specific location that's equivalent to doing a two to one benefit, because I'm able to unload. If I put it say on the 69 KV or the 115 KV I unload the 115 to 230, and it works up in voltages.

So I'm able to look at the benefit over a wide voltage range and over the statewide. And that tells me how much it provides as a value to the system, as far as an index, as an impact ratio to the system.

And so it's really is the fact that we do a contingency analysis, we analyze it and we weight the analysis by the number of occurrences in the voltage, and then we come up with a value in order to come up with a transmission value for the system, or transmission rating for the system.

It goes a lot more than that, I don't want to -- I was trying to simplify it, so if I install something that has a -2 it says that that location, if I put in 100 megawatts, it has a value as if it were actually 200 megawatts.

So it allows me to value what happens on the system.

MR. SMITH: What's the 200 megawatts represent? Is that randomly distributed 200 megawatts of generation, or is that the equivalent of 200 megawatts of randomly distributed load? I don't understand how you can install generation where you get more benefit than you're actually installing I guess is the --.

MR. DAVIS: Because we're looking at it over a California statewide, we're looking at it over a different voltage level. So if I'm able to unload some on the 115 to 230 I can unload my system so when I run contingency analysis I'm reducing the amount of contingency overloads I have.

So if I strategically locate it at a location I can reduce the number of contingency overloads that I have, the magnitudes of the overloads that occur, and so if I have say 100 lines that are overloaded, and I can strategically locate a resource that takes my 100 contingency overloads that I have, and I reduce them down by ten, that makes me 90 overloads, there's a benefit to the system because I reduce the number of overloads, I reduce the magnitude of the overloads, and the number of times the occur if I can pick locations that have a benefit to the system.

And so I can look at it over a voltage range and I can come up with a way of weighing its value.

MR. SMITH: Well, I'll have to e-mail you and ask you to inform me --.

MR. DAVIS: Sure. We can provide some more detail. It's, but it's a way of comparing on a statewide basis. I mean, if, we're trying to figure out a way of doing it across the whole state, so we can value something in southern California and northern California, and so we're trying to come up with a weighted value, or a way of weighing the transmission impacts to be able to compare resources in different regions.

COMMISSIONER GEESMAN: Ron, I'm wondering how important the geographic distribution of changes in load over time actually, or -- it's been one of the bones of contention with the Committee and our Demand Office in their forecast that it's not adequately disaggregated to where we would like to see it in the future.

And I think the utilities, in their transmission planning, build up from transmission planning areas, which I would presume have different assumptions about load growth, whereas our forecast, and I'm guessing what our staff provided you, is at a utility service territory, or yesterday they indicated that they may have made some effort to disaggregate it down to transmission congestion zones.

How important is that geographic distribution between now and 2010 or between now and 2017.

MR. DAVIS: It's very important as we go through it. And it's one of the things, as we were developing the PG&E data set, because I think PG&E breaks their system into eight zones or six zones, and they have a differnet load growth in each of the zones.

And one of the things as we began to apply the Energy Commission forecast for PG&E, and we were able to look at that, and then we were able to go back and look at some of the stuff on the loads that PG&E had given us, when you go over to the mountain areas and yo try to apply the average low growth you end up over in the control area and some of the -- oh, I'm sorry, that's the Edison area -- you end up with, in PG&E's area, that you get some really abnormal low growths in some areas.

And PG&E's been really good at providing us some information on these regions, that we were able to go and look at some of those but, yes, it is very important.

I mean, even down Edison's area, when we started looking at controls and you start using this stuff, it looked like the control on the Highway 395 is growing really large and the result is transmission problems, and it was really the area that's the factor, it is the regional growth, and we've really got to take what the statewide is.

And that's why we have to work with the utilities to see how we would apply that to the region, because we don't want to over-bias one area, but we don't want to under-do an area like San Francisco Bay Area or LA. So it becomes really a big issue.

And talking about the locational marginal pricing, that's one of the things we'd like to also incorporate, and I didn't mention that. We've talked with the ISO at times about tying in to -- I've had one conversation with the ISO about trying to tie in to some of their LMP numbers and in fact add that in to the analysis that we're drawing, but --.

I know the utilities have been really gook on trying to help us understand some of these regional growth rates and it's been really good to know more.

Some of the other things I just might say is, when we were doing the 2003 out to 2017, one of the things we did do was keep looking at these transmission areas and see that there wasn't anything abnormally happening as we were going out in our growth rates.

For example, if we started seeing, say Sacramento area increasing and then all of a sudden doing a decrease, well what occurred in to that. Well, that might be a power plant that came online, or it might be a new transmission line being built that changed a lot of stuff because it allowed more interconnection.

And so we went back and looked at those. And plant retirement, I think in one of the presentations, which shows some of the retirements in the Bay Area, really creates all of a sudden an area that increases and overloads of hot spots, because of the fact you're taking away local generation. So we looked at all those as we were developing it.

MR BATHAM: I wasn't sure if you were taking questions from the audience?

COMMISSIONER GEESMAN: Yeah we are, and yo need to identify yourself?

MR BATHAM: Mike Batham with the Sacramento Municipal Utility District. Ron, I have a question -- and there was some noise in the background and it was hard to tell for sure what your conclusion was, but I thought you said without transmission additions or upgrades that the state would have a hard time meeting it's 20 percent by 2010 goal for RPS.

If that's the case, would there be a difference in that conclusion if out of state resources but in-state projects using those out of state resources were counted in that analysis?

It seems like, in those analyses shown before, out of state resources were not included in coming up with the hot spots or the transmission issues associated with getting those resources in to California.

But nonetheless there are projects that use out of state resources, which are defined as in-state projects. So the question is, would that have changed your results?

MR. DAVIS: An out of state resource that's considered to be in-state? Did I understand --?

COMMISSIONER GEESMAN: What's an example, Mike?

MR BATHAM: Well, there are near California border resources that, if the project uses those renewable resources connects into the WCC, delivers energy into California by the definition that is at least as in proposed legislation, that would be called in-state renewable energy project.

So that would help define whether the true issues on transmission are all, you know, within California, or if bulk renewable power coming in from nearby renewable resource -- nearby meaning nearby to the California border renewable resources -- could then be brought into California with the existing transmission system that we have.

MR. DAVIS: Okay. We did not include out of state resources explicitly. One of the things was that utilities that are under contract are confidential, they're being negotiated. I know there's a lot of meetings that are currently talking about wind up in the northwest, those were not factored in to our analysis.

The other thing, when we looked at the -- and so, we didn't look at something coming in from Oregon and down across and look at its impact and fit it's analysis onto the transmission system.

However, when we were doing the out of state workshop, when we were looking at out of state resources, we studied the impact of bringing out of state resources from Oregon, Washington, Nevada and Arizona across our transmission system and what impacts did they have or what benefits did they have on to our system.

And one of the things that we saw and we presented in these findings was that the infrastructure starts to overload as you start bringing them down. You can bring them down on to the COI for a certain amount of megawatts, but then once you get to Tracy or you get to Orland or you get to a termination in SMUD's area, how much can you bring in before you start overloading the infrastructure there.

And we did analysis and looked at the impacts, but we did not include bringing those down as part of meeting the 85 percent target. And that's why I said if we look at those other contracts coming in we might actually get 20 percent or over 20 percent, because we do have contracts that you're bringing down that we did not consider because we didn't have access to that information.

But we feel that there are contracts that are being done, and I know four utilities that have contracts in the Northwest to bring down power that would pick that 85 up to a lot higher or eliminate some of the resources we have here that we showed because they now displace some of this other stuff that we're showing here on our table.

MR BATHAM: But that would also displace fossil generation, wouldn't it? In-state fossil generation?

MR. DAVIS: It could. It depends upon how you re-optimize and how you re-dispatch your system as you're bringing these in. And one of the things we did do is we brought these resources in, we did re-dispatch the system to a certain level as we start bringing these in.

And so we did back down some of the gas units and some of the fossil generation within the state as we started bringing in these renewables, because we're bringing in more than what we need. We don't need to bring in -- in order to meet our load growth and what we have on the system and what we have under contract we're bringing in more resources than we would normally contract for, I think.

So that we are backing down some renewables. The question that comes also in that, would be back down other intertie connections or would we not do certain contracts or change some of our contracts to make some of them more dispatchable to make room for wind.

And we didn't have time to incorporate those in there.

COMMISSIONER GEESMAN: Thank you. Nancy?

MS. RADER: Hi, Nancy Rader, the California Wind Energy Association. I'm kind of overwhelmed so I don't know if I'll be able to articulate all that I'm thinking, but I guess I'm alarmed by this report because we're at the PUC trying to get some CPCN's approved for Tehachapi upgrades, and it seems to me somebody could use this report and say "gee, we don't really need Tehachapi winds to meet our goals", and undermine actually building some transmission in the state.

So, am I right to be alarmed? And the other thing, I guess, my question is --

COMMISSIONER GEESMAN: I can answer that one real quick. No.

MS. RADER: Okay, good. I just wonder if this evaluation is at all consistent with what the RPS framework is, which is you take the generation costs plus the transmission costs and hopefully net out transmission benefits, which we haven't done at the PUC, at integration costs.

And look at the total cost of, say, Tehachapi versus some, you know, fire prevention biomass. I mean, I don't really see that result here.

MR. SIMONS: First off, if you look at Dora's presentation it does take into account Tehachapi. And one of the things that we do point out is that we do need the Tehachapi wind development, it's an integral part of this.

We've also said that we've looked at the phase one development of that and we've taken that into account. So if phase one doesn't go through, for some reason, then there are some problems, okay.

But the report does not portend that Tehachapi should not be built out, I'd say just the opposite.

MS. RADER: There's 900 megawatts, in your 20 percent scenario there's 900 megawatts from Tehachapi.

MR. SIMONS: Yeah, phase two would build it out to 1,400.

MS. RADER: Well, I think our Tehachapi plan counts on 4,000 megawatts by 2010, does it not?

COMMISSIONER GEESMAN: I don't think so.

MS. NAKAFUJI: In the proposal, as I understand it, Dave Wilson can talk about that a little bit later this afternoon, but only about 1,000 megawatts, or 1,500 megawatts for the initial first phase, proposed option one.

And then a planned expansion to add in

the remaining amounts in maybe two or three more phases after that. But the bulk of it is that there were about 4,000 megawatts identified down south.

MS. RADER: Yeah, but the Tehachapi plan calls for upgrades to carry 4,000 megawatts by the end of 2010. And this says 900 megawatts by 2010. That's why I'm concerned.

MS. NAKAFUJI: Right, what we had done was discussions with SCE was that there was this phased approach of the 4,000 megawatts. We're not bringing all 4,000 megawatts all in at one time and I think the discussion right now is how do yo upgrade to accommodate the planned amount of generation coming in.

So, the initial thing was a proposal to accommodate 1,500 or so megawatts of transmission with one upgrade. There's three upgrades needed on the 500 KV lines. So the first upgrade would accommodate about 1,000-1,500 megawatts, and then the other two would have to be done in order to accommodate the full 4,000 megawatts.

So it's a stepped process, and that was actually information that was provided through SCE and the Tehachapi group, so -- and again, one of the things is, the plan is really to work with the regional groups.

We did the, the SVA analysis was done over a period of about a year and a half, almost two years now. Moving in to the intermittency analysis and also SVA phase two the idea is, this is a methodology that gave us a baseline.

What we really want to do is integrate some of the regional studies that are now all happening with Imperial down in San Diego, even the Tehachapi working group.

The results are just now coming out. We didn't, they didn't know what that would be, we couldn't wait until those results to do this. So now, what we're doing is Ron is touching base with the Tehachapi working groups, through Dave Wilson. And also part of the Imperial working group now.

And what we're going to do is take the next step in the intermittency analysis and the plan that they have. But we also need to look at it from the statewide perspective and look at, well, other resources are also coming in. Down south there's a competition between geothermal and wind.

If we do all 4,000 megawatts of wind

down in Tehachapi what happens to the geothermal resource down in Imperial? So we're trying to balance that out.

MS. RADER: That's what we need to know, though. What we need to know is a least cost best fit kind of evaluation of what is the cost of Tehachapi transmission plus the wind cost plus integration cost compared to geothermal plus transmission plus integration.

MS. NAKAFUJI: Correct. And that's what we're moving toward. And so, the cost of integration looks at one component right now, and adds these transmission plans, and also the next step in the analysis.

We will be looking at those additional costs.

MR. SIMONS: Nancy, back in September we held a workshop called renewables transmission planning, and I had a slide and I actually wish now I had incorporated it into the presentation, the overview this morning.

There are many components to renewables transmission planning. Today's presentation covered one of them. We've got the cost of integration stuff, we've got the out of state, we've got the regional planning study groups.

All of those elements have to come in to really get a good system-wide, holistic I'll call it, approach to how are we going to roll out renewables in California?

Dora presented earlier that wind is probably the lowest cost renewable at this time. The real question on the table is the capacity factor, the effective load-carrying capacity.

So we're going to weigh all those things in the balance. You're absolutely correct, in a least cost best fit approach, we need to take those types of things into account.

The piece of the puzzle that's been missing, and we're going to begin addressing that this afternoon, is so okay, we've taken this whole statewide approach to things. Now we're going to hear from the utilities in the procurement bid process, how do they begin looking at it? How do we have to refine this tool to better take into account those things?

We've heard a number of issues raised about well, wait a second, you guys looked at a summer peak, you didn't do production cost modeling. There are regional differences.

Absolutely. And we know those things have to be taken into account, that's the intent of getting this feedback.

Nonetheless, maybe the most important finding that we could make is that regardless of whether the number is 85 percent, 65 percent, 70 percent, we can get down the path quite a bit of the way towards 2010, barring something that we hear today about cost, about some of the other issues involved, into meeting the 2010 goals.

And if we had to do it with just in-state resources we think there's a running chance to do it. We know we're not limited to that, we know that we can get some stuff out of state.

The puzzle's not built yet, there are still pieces hanging out there. So I understand your concern about this, I actually wouldn't feel too worried about this because I don't think that we've contradicted anything.

All that's happened is that we haven't been able to take into account the phase two planning efforts yet.

MR. DAVIS: One comment. It wasn't Edison, it was Dave Olsen and I had a long talk. And I took to be conservative.

We talked about what the phased approaches were of building the transmission, of getting the 500, of whether or not they'll get dealt with or not, about whether or not you'll get the stuff with FERC through, so there are a lot of issues associated with it.

And Dave and I talked and we decided to be a little conservative on the 900, because we wanted to see what other resources -- if we say we were coming in and we're going to show all 4,000 megawatts in here, and it was all dependent on all this 500 KV and all this 230 being built, then we're not looking at how we can do it to look at strategically located renewables to provide a transmission benefit.

Because we're really doing a tremendous amount of expansion. If there's any delays you're not going to meet it. So we're always conservative.

I'm conservative with Salton Sea also. I only show 600, 800 megawatts down here being built. If you can get it built and the wind and everything gets approved, and the Tehachapi goes, the the numbers will change and expand.

The other thing is we're only doing 20

percent by 2010. After 2010 I'm sure we're not going to stop and say we're just going to maintain, knowing we need 6,000 in 2017, that there's going to be more development and it's just going to keep going.

So it was a conservative estimate based on the fact of whether or not the transmission will get built. I, you know, -- and whether you'll get enough transmission built for 4,000 megawatts in five years, if you are, that's great.

MS. RADER: Oddly, that conservatism could actually feed into undermining the Tehachapi development, in that if you look at what the judge is asking for in the CPCM, she wants to know is this the least cost resource for the state.

Should we be building transmission to this resource area. And it seems to me that she could look at what you've done here and say "hmm, you know, I don't know, maybe not."

And unless we can show the PUC that we need to access this area to get the overall least cost renewable resource, all in cost, you know, it may not happen.

MR. DAVIS: Well, the ones that we put there when we looked at the LCOE's here, we did do the cost analysis of what they would be for the capital costs, looking at the transmission, with and without transmission, and we looked at it's impact to the transmission system.

You know, we could go into more detail in looking at the cost, but we tried to pick resources that didn't have a lot of transmission expansion.

We tried to do it with geysers that were close to existing lines, we tried to do some development of the Altamont Pass to wind and the other sites that may not require a lot of -- and I know there's the Berkhill (sp) development.

But I'm just saying that there's a lot of things that we looked at, and the idea was can we do it with a minimum amount of transmission expansion, and how close can we get.

And that was the target and that was the objective of looking at the different renewables. The biomass doesn't come in, for example, and Tehachapi, or, yeah, the Tehachapi can get your transmission and they can displace some of the stuff we're showing because the biomass doesn't come in, well then the -- this is just a plan, this isn't the exact that's going to get signed and never changed again.

This is an example, and it's a way of going about an approach and a methodology to compare alternatives. If we added in 900, we increased that to 1,500 at Tehachapi, what is the transmission upgrades, what is it's costs.

And then we can run through the LCOE and compare it to the other alternatives very easily, because the methodology is there.

MS. NAKAFUJI: And the other thing, too, is that, as George stated, we're looking at a holistic approach in terms of where we should strategically put the renewable resources.

It isn't only just wind. We know the Tehachapi is a large resource area. In fact Ron did do a separate study of that resource area and we specifically highlighted that resource area, pulling out the counties that can provide that resource.

And that actually confirms what SCE had come up with, a number of potentially 4,000 or so megawatts of resources down there.

So, I see that our results don't conflict with what the findings of SCE is, it's just, we, right now we're all working towards getting those numbers, the least cost best fit numbers, and I think that following this methodology and working with the utilities will achieve that.

I know there's was a time frame that you're looking to get the results out, but our separate studies do confirm what SCE found, that there's a lot of resources down there. And the transmission planning is a component that really needs to kind of factor in.

We could do all the costs, but the integration is really going to be the key piece.

COMMISSIONER GEESMAN: Sure, Hal.

MR. ROMANOWITZ: Hal Romanowitz, Oak Creek Energy. One thing I wanted to mention is that FERC did yesterday approve the Tehachapi trunkline. There are three decisions, we haven't seen them yet, but there are three separate written decisions, so there is at least a step forward.

COMMISSIONER GEESMAN: And possibly two steps back with three separate decisions.

MR. ROMANOWITZ: Right, exactly. And that's very true. And it's exactly why I wanted to make comments now, because I think the -- as we throw uncertainty into the process we raise confusion, and we need to be very careful, to keep a heavy focus on it.

And there is the 399.25 backstop provision, and uncertainty diminishes the push for that to go forward. And we need to complete the process, there's a lot of very good work in this.

As I listen to this, what Ron and Dora and George and all of them have come up with some very good inputs, but I think you have to also look at some of the uncertainty levels associated with those, that a lot of these are technologies that have other issues that have not been addressed.

The wind, like particularly in the Tehachapi area, has now gone through five or six years of process, and it is significantly advanced. And, like the 900 megawatts that Dora has used in what we're calling the central area of Tehachapi.

There's another 550 megawatts in the cue at substation five, which is at the Antelope Valley. And there's a lot of little things like this that are important to keep the focus, and we really need to keep it without diminishing.

Because the PUC is starting to revisit decisions already made, and we just have to keep the focus to get this done. It's enough of a hurdle.

COMMISSIONER GEESMAN: Well, let me respond, because I guess I want to reflect upon -- well, it's July 1st, so it's almost three years of growing frustration on this subject.

And I think that your industry and renewable advocates have to some extent contributed to the deepening problem by accepting the process that currently exists, and has existed for some extended period of time, as a given or as a desirable way to address our transmission needs.

It would seem to me that it is the height of folly to rely on a CPCN process, which unavoidably is going to be applicant-driven, to determine the pace or direction of buildouts of transmission facilities that are necessary for the state to achieve its goals in the renewable area.

I think the way in which the RPS statute was drafted creates an extraordinary burden on incremental resources. Maybe I'm wrong in its statutory construction, but I certainly think that the way in which the RPS program has been structured administratively puts the incremental burden on the incremental project.

So the renewable bids coming in to the program end up bearing this PRCR cost adder that the existing legacy system, the fossil generators that we're supposed to be trying to displace, they don't bear that burden whatsoever.

I don't know why we maintain these arcane deliverability requirements for output from renewable facilities that in essence restrict the bids to the local utility service territory when we don't impose the same kind of requirements on other resources.

And I do think that your industry and renewable advocates in general, in addition to the PUC and this Commission and the Legislature and the Governor's Office, have all inadvertently combined to be part of a conspiracy to do nothing.

You know, we haven't really moved off the dime on this. The Governor's tried to change the organizational configuration in transmission planning and transmission permitting, but we don't seem to have gotten anywhere.

And I reflect on 35 months now of watching this problem, and watching the problem not get any better.

MR. ROMANOWITZ: I appreciate very much that, because this helps to amplify some of the frustration that we're feeling, and this meeting today is the third meeting this week on Tehachapi transmission.

And the meeting yesterday that we had in Ontario, which was the SCE-Cal ISO stakeholder meeting, we were reflecting -- we actually had an extremely productive meeting by the way -- but there was a lot of reflection.

It was 1998 that we started the process, to get this thing moving forward. So we've been working on this now for quite a few years just to get the process forward. And I think yesterday we had, at least there is some verbal effort to try and integrate the existing with the new.

Because in the process that's going forward now, you're talking about new transmission and so far have not been willing to look at how it gets integrated together.

Now at least there's going to be some discussion about how we cause some integration, and this may help the process. And I do point out at the same time that those from the industry that are here are all here at their own expense, whereas those from the utilities and from the regulators are all paid for it.

And my company, in particular, has put in a tremendous effort into breaking this loose. We started the process at the PUC to break it loose. Really, you know, just, took a real beating to move the process forward.

But it was successful, it did get it started. And that's okay, as long as we can make this thing move forward. But it's, as I say, we're very frustrated that in fact when we do put our effort into this that we not get 80 percent of the way there and we find out, well we're going to have a shift in direction and go another way.

So we want to work with you, we want to help, we're trying to do things to adapt the projects that we're dong to make them fit better and to fit optimally. There are a lot of things that we've been trying to do, but we've got to get the contracts so we can build projects.

COMMISSIONER GEESMAN: Yeah, well I would compare the way the state's gone about reconstructing the Bay Bridge with the way in which it went about reconstructing the Santa

Monica Freeway after the Los Angeles earthquake. And I think we've got to be on the Santa Monica freeway.

MR. ROMANOWITZ: Yeah, right, Tehachapi's closer to Santa Monica, so maybe that's a good omen. But we need one or two. Thank you.

COMMISSIONER GEESMAN: Thank you. Other comments or questions?

Why don't we take a lunch break and come back at 1:30.

(Off the record.)

COMMISSIONER GEESMAN: Why don't we go ahead? Commissioner Boyd apparently has another commitment.

MR. PRICE: All right, I think we're going to go ahead and get started. If everybody could find a seat?

My name is Snuller Price. I'm a partner at Energy and Environmental Economics, located in San Francisco.

I'm going to spend a few minutes talking through some of the findings and methodologies that we developed on a CEC PIER project called Renewable DG Assessment.

Our focus was really a parallel type of problem to the strategic value analysis that we saw this morning, but focused really on a local utility scale.

Just a quick overview of my talk. I think I have three slides that try to summarize the whole project, and then I've got a number of slides that go into some details on specific pieces of the evaluation methodology that we used that particularly focus on local value of renewables.

And those include the capital referral, reliability losses, and environment intangibles.

And I think there are a lot of parallels between the methodologies we found on these components and the presentations we heard his morning on a statewide scale. So I want to kind of point out some of those comparisons as we go through.

I'm up here talking through this, and I think I have presented some of these slides in the same room before, probably to some of the same folks.

I think it's important for me to point out that, even though I've been up here talking about these there's a whole bunch of partners that we've had in this project, including those here at the CEC, at San Francisco PUC Hetch Hetchy, which was the prime center for resource solutions, a number of people on our advisory committees, engineers at Electrotech Concepts who are now at EPRI solutions, and all of our client utilities.

So there's a whole bunch of people that have been working on this, and I just wanted to acknowledge that.

Our role in this project was really to do the economic analysis, tradeoffs of costs and benefits of the renewable energy resources located at these utilities. so that's what E3's role was.

Electrotech Concepts was really an engineering analysis of what was the impact of actually putting generation within the municipal that we were working with.

And we did four case studies, and these are all utilities that either have active renewable programs or genuine interest in putting renewables in their service territories.

We're going to talk about what technologies and so on, but they all wanted to find successful projects that they could actually then go out and procure and build and have renewables located in their municipals.

This is oftentimes one of the last charts that I show about the project, and I just wanted to put it up there and make a couple of points about our overall economic analysis.

The first point is we looked at a whole range of technologies, from bio-gas, which we were using as sort of a generic term to include landfill gas, if a particular municipal had that resource, to a bio-gas like a digester type, biodiesel, solar, wind --.

And the list was quite broad. Anything that they wanted to look at, we weren't confined to one renewable technology or another.

The other thing I wanted to point out is that we looked at the economics of these resources from a bunch of different perspectives, from the utility if it was a utility built and financed project to if it was say, a rooftop solar type of project, a participant, okay, how does that customers' bill look.

To a sort of a community wide or societal cost-effectiveness. For example, is the overall cost of energy higher or lower in Alameda as a result of this project?

So, the bottom line answers that we found is, as you might guess, those applications that use renewable gases and have a waste heat recovery element to them, so that you're getting some process heat or hot water or steam and you can put that to useful work, had by far the best cost effectiveness results. So, that sort of rose to the top.

The other thing, while we were really focused on utilities looking in these utility service territories, everybody wanted to look at well, what happens if I look at large wind. So we put large wind in our resource mix and found also cost-effective applications on the wind side.

COMMISSIONER GEESMAN: Snu, could you explain the columns?

MR. PRICE: Sure. Each column represents a particular perspective, look, at the economics. And there's some jargon involved. The TRC cost test stands for Total Resource Cost, so that's sort of the community cost-effectiveness that I was talking about.

There's the participant, which is either the customer, if it's a behind the meter application, or if it's a merchant plant that's directly connected to the distribution system.

There's a RIM test, which is an estimate on the impact of rates to the utility. So it's called the Ratepayer Impact Measure, that's the acronym. So that is, if I do, for example, say a five kilowatt solar rooftop PV installation, and you do all the costs and all the benefits.

What you'd find is, from that RIM test perspective, I'm getting a BC ratio of .57, for example. Which means that, relative to procuring business as usual procurement for that utility, my rates will go up.

And behind that are a whole bunch of assumptions about how my program looks to encourage solar rooftop systems, and so on through the different technologies.

Utility cost test is impact to the utilities revenue requirement. So what that will tell you is the total amount of money that I'll need to collect from customers, greater or lower.

The difference between the RIM test and the utility cost test is that, for behind the meter applications my actual throughput has gone down so I could have a rate impact.

COMMISSIONER GEESMAN: And is there a reason why your RIM test results are so much more convergent than any of the other tests?

MR. PRICE: Yeah, from the RIM test perspective the costs that are going in here, from a utility perspective, are really the lost revenue. And the benefits are really what a procurement wholesale price is. And those are really independent of technology, right.

So if I have behind the meter a rooftop PV or if I have behind the meter, say I'm a commercial customer and I have a CHP-type unit, the relevant costs and benefits work out the same. Because I don't actually have the cost of that technology in there.

COMMISSIONER GEESMAN: Okay.

MR. PRICE: Key results we've found across -- and I'm trying to summarize across our four case studies -- is that it's difficult to find, circulate cost effective renewable DG on a net benefit basis. We found it tough.

Avoided costs are too low. That's another way of saying compared to wholesale energy prices and transmission costs for these utilities, compared to in particular the capital cost of the technologies that we looked at, it's tough for them to find winner projects.

However, as part of our project and I'm going to talk about this a little bit later, we really did value the indirect benefit and started to talk about well, if I have to pay a premium for in-area renewable resources, how much is that going to be. And starting to weigh that off against some of the indirect benefits.

The cost effective technologies that we did find tended to be combined heat and power applications, as we saw, in terms of those that are connected on the distribution system.

The other point that I want to get to, and sort of talk about for the rest of the presentation really, is what are the local benefits on the system of having renewable DG interconnected on my distribution system.

And the key that we found is that, when you're working with the engineer on that system you can find these hot spots, just very parallel to what Ron was talking about, from the distribution system that provide a big benefit. And I'll show you how big.

And if you don't do anything, you just

have it okay, customers are going to adopt something on sort of a uniform basis, you may not pick up those hot spots. That'd be the equipment of putting renewables wherever in the state, you may not hit Ron's red circles.

So let's talk a little bit about each of these components. And again, from a perspective, we kind of had all the pieces in place, because we had the utility engineers who had a real good knowledge of their system.

We had the utility, who really wanted to find projects, maybe even sponsor them themselves, so we basically could have almost a developer type perspective on well where would we put these things?

So that was sort of our perspective. The value, again is very dependent on location. And I think without the utility planning process involved it would be hard to hit the high value applications.

For example, and this is just a picture of the Electrotech concepts used for Palo Alto, is they can model the entire system and then find out okay, if I'm going to put a two megawatt combined heat and power application here on the system, what are the best locations?

So I've got the dark blue as being better locations, but you can really define okay, within my utility, where would I choose to suit those.

And this example is based on release capacity. And we could also do that based on reliability, and I want to talk at the end, the last component I want to talk about is reliability.

Because all of the utilities that we worked with and all of the issues they had, reliability was definitely the number one mentioned aspect of local value they wanted to explore.

Skipping up -- this is just a list of what we're going to talk about.

In terms of capital deferral, when we started this project we really thought that the number one local benefit was going to be capital deferral. So, distribution system infrastructure that wouldn't have to be built because of the reduced loads on the system.

And when we got in to this in the 2003-4 time frame all the utilities, except for the SMUD case, were down. The economy wasn't doing as well, they had all the capital projects they needed, so there wasn't a lot of opportunity to defer anything, it was just deferred because the loads were low.

So the result of our project ended up focusing on other benefits, we didn't get as much as we expected. Alameda and Palo Alto basically had no capital projects on the capital budget plan.

For the section of the SMUD service territory that we looked at, there were identifiable capacity upgrades. The area that we had, though, when you actually quantify if, how much value is it to push that investment off versus how many kilowatts do I need to actually push it off, and then again to maintain reliability is pretty low. On the order of about $2 a kilowatt year.

$2 a kilowatt year for those who aren't used to using all these units is a very low number. Now, if you think about the cost of a PV system amortized over 20 years it's cost would be several orders of magnitude higher than that.

Hunter's Point Naval Shipyard in San

Francisco was actually an interesting case, because instead of putting in new distribution generation in any area that's already built out it was really looking at a redevelopment of part of the city that had basically not been used.

The Hunter's Point Naval Shipyard is an area that was a shipyard and is now essentially abandoned and they're looking at redevelopment. So, as part of your redevelopment plan can you incorporate local generation to reduce your costs and approve.

And in that case we did find that there is some higher potential, there is some value. There are some reliability tradeoffs but there is a lot of value in planning the system from not quite scratch because it's a redevelopment but while you're doing major infrastructure development of siting in-area generation.

I wanted to mention losses a bit because we actually found that losses add up, and you can get quite a bit of value from losses. And what I have here is again a Palo Alto example, and each of these rows are a different line in terms of a project development.

So, for example the first row is four

megawatts distributed all across Palo Alto's service territory. The second one is two megawatts at one particular place, the VA hospital in Palo Alto, as a peaking type of unit and then as a baseload unit.

Ten megawatts, the best locations we could find, no matter where they were. And so on. And I think that the best column to look at is probably, because it normalizes it to the size the project is, is the generation kilowatt hours.

So, for example, on this four megawatts of PV, in terms of losses over the course of the year I could say about 2 and 1/2 percent of the energy that PV generated on losses on the system upstream, and so on.

And what you find out is these numbers kind of vary, okay. And it varies quite a bit by the size of the project, where it's located, and how it operates. Notice the peaker saves more than the baseload, even at the same size and location, because it's focused on different hours and it's reducing loads during higher loss periods.

Kind of bouncing around to these different local benefits. One of the biggest issues for everybody was well how do I quantify and calibrate these indirect benefits?

And the way we did our economic analysis is to go through and basically compute costs and benefits without including anything that we didn't write a check for or receive a check for. So we did just direct money coming in and out.

And then we compared any shortfall with a list of indirect benefits. And to quantify the indirect benefits we actually held workshops where we would sit down with the utility resource folks and just sort of walked through the different installations that we were considering, and a list of potential benefits, and basically at the end of the workshop come up with our list.

So for example you could have a rate impact of this, but you also get renewables with this set of indirect benefits. And we were able to kind of directly do that tradeoff.

The indirect benefits map is drawn into three categories, a general renewable value, renewable type specific values -- so those are specific to say solar wind, biomass, or other -- and general value, just for having distributed generation.

And we don't have time to go through every piece. The way we got our list was culling through the literature of the different indirect benefits people had quoted and tried to categorize them into consistent but not duplicated sets of indirect benefits.

The last piece I wanted to talk about quickly was the reliability analysis, and we spent a lot of effort linking together the engineering model of the system and the economics.

And one of the places that that came together was on the reliability analysis. The tool that Electrotech Concepts used for doing this was a load flow model, but rather than looking at just the peak value of the year they actually ran the whole 8,760 hours a year of load flows.

So they could look at what's happening on their system at each point. And the value of looking at these over times is that you can start to get a sense of, well not just how much am I going to be overloaded on my highest hour, but how many hours am I talking about being in any part of the year where I have a lot of risk.

And the basic definition was then to define a normal limit. We defined our normal limit as the amount that I could, the amount of load that I could pick up within one switching operation on my distribution system.

So if I had a problem I could pull one switch and then I could basically pick up all the load.

And then the emergency or maximum is the maximum I can serve without any contingencies or problems on the system at all.

And with this approach you can take the loads by each distribution theater and compute these metrics that we calculated.

One is energy exceeding normal, which is the amount of load that I lose if I have a contingency. And I have unserved energy, which is the amount of load I have to shed just to protect my system.

And we can compute these before and after I put in my renewable DG and we have a comparable basis in terms of reliability impact of having that local resource.

The EEN, or course, you have to assume some probability of actually having that contingency. So we have a probabilistic analysis based on the value of customer service and losing that service type of framework.

And I wanted to show some examples of what that does. These are some pictures of the output for the SMUD area that we looked at. It's just north of here I believe. And it's just evenly distributed 20 megawatts of PV on that system.

So what would happen if we did this one case. And if we do that, we've got our hourly model, and we've got an hourly mode profile, which is shown here, this black line, and then we've got this PV output -- and these have been normalized so I can show them on the same chart.

And what you'll find out is that the PV output is pretty much consistent, and it's all in the middle of the day, and you get output coincident with all the loads leading up to the peak, but you really, the PV is rapidly decreasing at around 4:00 or so.

And that's when the load facilities, in the SMUD service territory at least, were peaking. So I'm getting a portion of my peak, the leading part, but I'm not capturing the peak, they're kind of crossing right there at the peak, right.

So then if I, what that does with my EEN metric I've got, I've got the load in that area before and after, these charts here. Before and after I put in my 20 megawatts, and this red line is the difference, and this red line is against this right axis.

And what this tells me is that for 20 megawatts of PV I can increase the load in this area by about eight megawatts or so and I get back the same reliability I would have had without the PV. Does that make sense?

So I'm not getting 20 megawatts in this case with just spread out evenly PV. I'm not getting 20 megawatts, I'm not getting zero, I'm actually getting -- and we ran the engineering tools to show that, in this case I'm getting about eight megawatts.

Similar example for Palo Alto, but this time we picked the best municipal buildings, locations to municipal buildings that were closest the the best locations. And so we're trying to evaluate real sites, and we evaluated a plant that would distribute 570 kilowatts of PV to these locations.

And what you'd find is -- Palo Alto's load is a little lower -- what you'd find is at different load levels I get different value for that, but sort of at this load level they're projecting to go into at not too distant future they get about 570 kilowatts of capacity relief for 570 kilowatts of PV.

So they're actually picking the right locations, they're actually getting quite a bit of value in terms of this reliability metric we created.

So, that's the quick summary of the pieces I thought we should pick out. And I'd be happy to answer questions now or --?

MR. SIMONS: Thanks, Snuller. We're going to shift and Hank Zaninger will be talking about the Chino Basin.

MR. ZANINGER: Well, thank you. We're going to be shifting gears here a little bit. I'm going to talk about a power flow study that I did on a mini-grid in the Chino Basin.

And so we looked at various kinds of renewables. This basically, what we're going to do is, I'll just present an overview, because there's a lot of slides, a lot of work, a lot of things happened.

First of all, the area we're talking

about is about 12 miles wide by 11 tall. And it's in the Chino Basin, and it's in the service area of Southern California Edison.

The renewables that we studied here were non-residential building integrated photovoltaics, dairy waste and wastewater biogas, as well as landfill biogas technologies added in to this mini-grid, the distribution systems in that area.

And what we evaluated, other participants in this project -- and by the way, this project's part of the commonwealth PIER renewables energy program, and other people that worked in this task, which is task 1.1, were ITRon and CH2M Hill, and they developed expected high and low penetration levels for this mini-grid area in 2007 and 2012.

So what we did was develop the mini-grid model and then we performed the power flow analysis to determine the potential of local T&D impacts and values that we could quantify based on the information we had.

What we did -- I'm talking about the power flow aspects of this, and so basically in order to develop this system we worked closely with Southern California Edison. We really had close cooperation and interaction with their personnel in developing this.

Much of the data that we collected was based on proprietary data which they made available for use in developing this min-grid. So they had like substation data, feeder data, configuration, ratings, conductor sizes of the feeder conductors, projected peak loads and substation data at the substation.

So we then developed representative electrical parameters from publicly available sources and laid out the mini-grid database. So that's basically what we did. We used their circuit maps, and actually street maps, to lay out the systems.

We then added local sub transmission data, and we took all this information and we plugged it into a bulk transmission model for WSCC. So that is what we did.

Now what happened, we had several iterations in developing this system, and the result, we wound up with nine 66 to 12KV substations, and 72 12KV feeders were in this 12 mile wide by 11 mile tall area.

The mini-grid load, the peak load that

we started with, was 565 MVA, and Edison's policy is close to unity power factor, so that's about 565 megawatts. So the nickname for the mini-grid was mighty grid, because if you look at this number, this is larger than 2,000 buildings in the US, okay.

And it's about one percent of California. So this little area had a lot in it.

We the expanded this system out to 2007, assuming a three percent load growth, and from 2007 to 2012 assuming a 1.7 percent load growth. And these data were based on Energy Commission assumptions and data that they had produced.

We then took the system, we added appropriate transformer and feeder capacity as needed to serve these load increases, and finally we determined appropriate light load case primarily to look at potential reverse power flows.

All right. This in a nutshell is what the resultant system looks like. Generally we use a math that nobody could read, so I thought I'd -- I didn't want to win the reward for the worst new grid, or, you know, so we used this instead.

So, where is it at? First of all,

here's Route 10 going along here, and here's Route 15 going along down in through here. So this route in here is the Ontario Airport, down here is the outskirts of Corona. So that's where the mini-grid is.

If you look at the representation here, these red dots show the approximate substation location within each of the distribution systems that we wound up developing. And the rest of the area is served by the feeders emanating out of that, each of the substations.

So you had a feeder like, substation A is ten feeders, all of them are in the mini-grid. If you look, all of the feeders in the substation are included within the mini-grid.

Now in addition we had substation I, which actually has 13 feeders coming out of them, but 3 of them were included in the mini-grid.

And substation U had eight feeders, but two of them were in the mini-grid, so they were added. So this is what the mini-grid looked like.

Down at the bottom end is kind of rurally, okay, there's where dairy farms are, things like that. But I call it rural-ish, because there's dairy farm, dairy farm, dairy farm, subdivision, dairy farm, dairy farm, prison, subdivision -- you know, I mean it's not just rural. But it's kind of rural as compared to the rest of this highly urban area here.

So what we did is, this kind of shows the transformer additions that we added. We added 28 MVA transformers, which is the standard size that Edison would use to add to expand their distribution systems in these urban areas.

You can see that the pink ones show that transformers were added to, actually A, B, E, and I in 2007, so 20 megawatt transformers had to be added to serve the load for the load growth in the relatively short term.

2012, you'll see, let's see, B, C, D, and G, these all had transformer additions in 2012.

And one of the areas did not have any new transformers added.

Now, the other thing is that, I'm going to start saying location-specific or site-specific every five minutes for the rest of the talk, because all of these potential T&D benefits associated with adding distribution generation in here are site-specific.

So if you had the potential to defer some of these transformer additions, you'd be located in any of the shaded areas, okay. If you were in say B, if you wanted to defer that, if you're DG is located in here, you could have the potential to defer that transformer addition.

So if you have a lot of DG in F, you can't defer a transformer. You're going to see the largest -- as Murphy's Law says, that's where the largest reduction is going to be when we get there.

Feeders, we had to add several feeders. In substation E we had to add a couple of feeders in 2007, in substation G and I we each had to add feeders. To add the potential to possibly defer these feeder additions the distributed generation had to be located in these shaded areas.

Now notice that you had to be, if you're in say substation G you're in the white area, you're in the wrong area and you can't defer the feeder additions, okay. But if you're -- you have to be in the shaded area. So, again, it's location specific.

2012, in substation A, or distribution system A, there's a couple of feeders that had to be added there, and if you had the potential to defer those feeders you had to be located in the shaded area here.

All right, the expected high and low renewable penetration levels are shown in this slide. These are developed by ITRon and CH2M Hill as part of this project, and these are based on market studies, not maximum technical potential or anything like that.

So the expected amount by 2007, which when we did the study a couple of years ago that was about five years out, is about ten megawatts. And here's the mix between the photovoltaics and biogas.

The high penetration scenario is up over 29 megawatts, and the low megawatt scenario, forget about it as far as C&D benefits, but it was six megawatts.

By 2012 you had up to, you could get up to, close to 28 megawatts was expected, and 54 was the high penetration scenario and again the low penetration scenario was really not very significant.

Now compared to the mini-grid, or mighty grid peak load, that was 621 megawatts in 2007, and 672 megawatts in 2010. So if you note, the penetration, it's actually low penetration relative to the size of the mini-grid system. So that's what is expected.

Now the performance. From CH2M Hill and from ITRon we got performance data for the renewables. For the biogas performance was basically 24 hours a day, close to the nameplate installed capacity.

So for this study we assumed full output. In a sensitivity case we reduced the output ten percent to allow for forced outages.

Okay, the, you look at this blue line up here, and this is kind of a Southern California Edison load shape. Notice they're at like a midday peak, different than for what he showed you for SMUD.

SMUD, which was more like 5:00 in the afternoon, doesn't correlate as well, but this really has good correlation with photovoltaic output in that area.

Now notice the photovoltaic in the summer was de-rated to about 92 percent, and that's common for photovoltaics. If you have nameplate during peak load conditions you never seem to get the full output. So that really would be de-rated to 93 percent, which we assume in this particular study.

And then we took a sensitivity case, where we further reduce to ten percent to allow for poor salvages of photovoltaics in the system.

Now notice in the spring and fall you had about 80 percent, it got up to about 80 percent, that's what you get of nameplate. And then the winter you're up as much as about 63 percent.

I told you about a light load case. We set up a light load case. If you look at, in the midday time frame, on weekend days throughout the spring and fall and winter, the off-season, you're at about 50 percent of the peak load.

So we set up a light load case of 50 percent of the peak load, which would cover a lot of the days, and we wanted to look at the midday where the photovoltaics are operating, obviously looking at it at night wouldn't be very exciting because there wouldn't be as much impact then. But during the day we wanted to look at light loads to look at potential reverse power flows.

And what we did in the power flow

studies is we looked at a number of different impacts. And since I hadn't said location-specific or site-specific I thought I'd throw that in because it's been five minutes.

So we looked at power flow reduction mainly at the peak. We looked at loss reductions when distributed generation is added. We looked at voltage regulation. We looked at reliability in particular with the idea to defer the distribution facility additions, namely transformers and feeder additions.

We also looked at flicker to see if the distributed generation could cause flicker problems. And again we looked for power flow impacts.

Just really quickly here, this being an overview. Remember we added transformers in 2007 at A, B, E, and I. So the rating with these transformer increases is shown here for each of the substations, and these are the base case loads without the renewables added.

For the expected high and low penetration scenarios you can see what the MVA reduction associated with each of them is. And of course the largest reduction was in distribution system F, which didn't need a new transformer addition.

That's Murphy's Law, that's the way it always works. However, if you look at E, you're getting about three percent reduction here, but remember the load growth was about three percent out to 2007, so to defer that particular transformer you had enough capacity to defer that in the high penetration scenario.

2012, things are looking a little better. There's two aspects. First of all, you had more penetration of the renewables so you got more MVA reduction. ?The other side of the coin is the load growth was slower, it was 1.7 percent a year, so you also had a better chance of deferring distribution facility additions.

Again, F did not need a new transformer, but it's getting close. Within the study period it didn't need any new transformer additions.

If you look at loss reduction. We looked at peak loads and light loads. And the good news is we had loss reductions both during the peak load conditions and light load conditions considered in this study.

We didn't look at enough points to

really quantify what the lost reduction benefit would be in the study. I didn't get too excited about it because I actually remembered the penetration in the mini-grid was low, less than ten percent of the peak, so the actual loss benefits are expected to be relatively low anyway. But there is loss reduction potential benefits there.

Flicker, we looked at flicker. I just want to show you, this is kind of an interesting situation to see if you have problems. Well, what happens is, if you have a voltage drop and it gets too high, say from renewables switching on and off or fluctuating, they can cause voltage drops in the system.

And this is frequency, this is like the flicker curves. And as you can see, the more frequently they occur the less you can tolerate. And really the main purpose is irritation curve, okay, there's perception and irritation curves.

These curves have been around for a long time and they're commonly used by many of the utilities. For this particular study and the renewables included in the study it looked like the voltage drops associated with them would incur infrequently.

So, basically, for that criteria it'd be about five percent that they could tolerate without irritating the other customers in the area. And when we did the study we saw things were all less than three percent, so we didn't see flicker as being a problem here.

Reverse power flow. Okay, this is where the substation is. These ones and twos are generation locations in one of the feeders that we evaluated in the study, and this is kind of the end of the feeder.

And if you look, you can see here, this is power flowing into the distribution system. And that's reverse power flow. Without the generation the power would be flowing the other way, out into the feeder. That's the normal way for distribution system.

So we did how reverse power flow. And from this there was a couple of things that we found out.

One, reverse power flow has the potential to cause voltage regulation problems on the system. So we identified, that's one potential problem that has to be addressed if you're going to have high penetration.

And by the way, in a couple of instances we had fairly high penetration out of some of these feeders. And if you look at this voltage here, this is 1.033. They have tight voltage regulation criteria on these urban systems in California.

So this is a little bit out of tolerance, so that confirms that there are potential problems that are going to have to be solved. Generally you would do that with a more detailed facility study or system impact study.

The other thing is that this indicates that relaying requirements are going to have to change probably, with reverse power flows, with this generation in there. So it identifies that these are issues that will have to be addressed with a more detailed facilities study.

Cost data, we did some cost data. And basically a 28 MVA transformer, the installed cost, which we got from Southern California Edison, would be about $600,000 to $1 million to install one.

Underground feeders cost anywhere from $400,000 to $650,000 a mile to install. Overhead feeders cost maybe $150,000 to $300,000 a mile to install.

Well, if you look at what we did to expand the system and accommodate things by 2007, it's about $14 million. And these are fixed charges, annual fixed charges associated with that.

And if you look at 2012 there's another $12 million that had to be added to upgrade the system to accommodate the load increase.

And the potential benefits. Well, just to summarize things, the highest potential benefits for the high penetration scenario, that's what this means here. And these are significant benefits.

First of all, what we want to say, and I put them on a dollar for kilowatt basis so you can compare them with the cost of the distributed generation. Otherwise you see a lot of numbers and it's kind of hard to put that together.

But there's two things I want to point out here. First, in the substation E, the transformer deferral was worth $130 a kilowatt, but the feeder additions also on E was another $560. So that totals about $700, if you're in the right location.

Remember the substation E feeder additions to DG had to be in the location that was shaded on the previous slide that I showed you. And anywhere in the substation E service area you've got the $130 per kilowatt, so that's significant there.

If you look down to 2012 and if you deferred these other two feeder additions it's over $800 a kilowatt potential benefits.

So, basically, in summary, the significant distribution benefits were determined as part of this study.

And a couple of other things that we observed and found in doing this. First of all, you could expect high distributed generation penetration of six to eight megawatts within the next five to ten years on some feeders. Even though the penetration is actually low on the mini-grid basis, on the feeder level there's going to be high penetration.

Well, this is about twice the present allowable penetration levels typically allowed on urban distribution feeders now. High penetration now is two to three, this is twice as much. So we found that. This is new territory.

So new territory is going to occur with the renewable incentives that are in place and that are going to continue to be in place. This is going to occur, and it's going to occur within the next few years. This kind of stuff is going to occur before you see the transmission system impacts.

COMMISSIONER GEESMAN: Hank, how do yo figure two to three megawatts is allowable now?

MR. ZANINGER: Well, basically from experience.

COMMISSIONER GEESMAN: Okay, so it's, two or three megawatts is what you're seeing now.

MR. ZANINGER: It's a lot, yeah. Now, you can see some places where they'll have two or three megawatts on there. You might see more, especially if the generation is located right next to the substation.

For example, the Chino Battery, which was in place down there in that same area for a number of years, was 10 megawatts, located right at the substation. Well they could take ten megawatts there.

But generally you're going to see two to three as the maximum allowable. If you look at Rule 21, I think, you start having special studies if you get over 15 percent. So --

COMMISSIONER GEESMAN: Oh, okay.

MR. ZANINGER: -- 15 percent of nine or ten megawatts is, you know, a couple. So --

COMMISSIONER GEESMAN: So it's Rule 21 that's driving what you consider to be allowable?

MR. ZANINGER: Yeah, that's allowable. You know, I've been around awhile. I don't know if you notice, but my hair is getting a little grey. But in the past the distribution people were really anti-generation. And things have really come a long way.

And now, they're talking generally two or three and they can accommodate it. That's the way, that's what their thinking. You have to think differently again to double that.

Because then, when you double that you want -- this distributed generation has to be a significant part of the reliability of that distribution feeder, where now they're just accommodating it.

So if you look at P1547, the working rules and stuff like that, they're all thou shalt not do this and that and this and that, and that's where these kind of limits are, so we have to think a little differently to increase this penetration.

But I tell you it can be done, it just has to be shown that the system's going to operate all right. And, you know, there are several hundred customers on a feeder, that they can have adequate power quality and reliability when the distributed generation is added.

So, I guess the other point I wanted to point out from the slide is that similar results from this study you can expect on other urban distribution systems in California as well.

And, by the way, this detailed facility study was recommended by the TAC at the project CPR meeting.

So what does that mean. It's just the next step, and this probably will be done. Again, we're talking high penetration, maybe twice as high as is typically allowed. So in order to do that you can't just do power flows, which we did.

We could identify things -- and I didn't see any real showstoppers -- but what you have to do is you have to look at potential relaying requirements with this high penetration, you have to look at integrated voltage control on the system to make sure it operates properly.

And one of the things that I saw that is one of the things you have to look at is you have to look at short circuit through the impacts.

And another thing you have to look at here is the dynamic response, or the transient response to nearby disturbances. And I'm not talking about islanding, that's another thing that people jump up and down about, let's not worry about that now.

But if you have a disturbance on an adjacent feeder, or in a sub transmission circuit, you don't -- when you have six to eight megawatts of generation on your feeder you don't want to trip it off when it's not supposed to.

So in order to do that you have to do dynamic plots of what happens to the voltage after a disturbance occurs, to see what happens. And mainly what you really want to look for is you want to find the ride-through capability of the distributed generation for this high penetration.

Where it was low and you're accommodating, you don't care if it trips off.

This is kind of analogous to, everybody was talking about wind this morning, of course I'm presenting a lot of wind here right now, right?

But in the midwest, they are putting in a lot of wind farms. And they're large, hundreds of megawatt wind farms are going in. Of course, we already got a couple of thousand here in California, we were here first anyway.

But putting them in, I was talking to one of the planners at MEC, which is MidAmerican Energy Corp, and I remember in the late 90's, when they were putting their first wind farm in, which was maybe 100 megawatts, and they didn't care. They wanted it to trip off. If anything happened they wanted the wind farm off.

Now they've got 360, and everything - at a conference they just had a month ago they kept talking about ride-through capability for the wind turbines, and I think you wind people are hearing about that.

And so now -- and the Europeans also,k they have high penetration and they're all worried about ride-through capability. This is the biggest issue for them now. So we have the same kind of thing that's going to happen at the distribution level, I believe, when you have high penetration there.

So that has to be addressed. If you address it ahead of time you can have successful integration of the distributed generation on the distribution systems.

COMMISSIONER GEESMAN: Let me make certain I recall your description of the mini-grid properly. Did you say it was about 11 by 12 miles?

MR. ZANINGER: Yeah, if you looked at the width on there it's about 12 miles. It's a couple miles on the east side of 15, and the rest is, you know, Ontario and Chino and stuff like that. It goes down to the outskirts of Corona, and if you looked up, there's a little spot at the top, that was up above 10 and then 15 came along there.

So, from that down to the other, that's the area. It seems like kind of a small area, right.

COMMISSIONER GEESMAN: Well, I was going to ask, did you say 565 megawatts or load currently?

MR. ZANINGER: Yes.

COMMISSIONER GEESMAN: That's pretty dense --

MR. ZANINGER: Well, 565 megawatts served in that area.

COMMISSIONER GEESMAN: That's pretty dense load, is it not?

MR. ZANINGER: Yes. That's why I called it urban. And when I said rural-ish, I was kind of snickering a little bit, because if you go rural, there's rural places where you go mile to mile, you know, but it was kind of rural-ish, there were farms, and it is a little less dense than the upper part of it.

COMMISSIONER GEESMAN: But it picks up the Ontario Airport?

MR. ZANINGER: Yes, the Ontario Airport is in there.

COMMISSIONER GEESMAN: In terms of the high penetration that you're describing, is it most likely that that would occur in other similarly dense load areas?

MR. ZANINGER: Yes, I believe that's correct. Now if you're going to look at rural areas you're not going to be able to take that kind of penetration on rural adders.

COMMISSIONER GEESMAN: Right. But, as a consequence then, to replicate this scenario or to learn more about it, we would want to focus on those more dense load pocket areas around the state?

MR. ZANINGER: I think so, because one, at least for photovoltaics, there's a lot of roof area in those urban areas that can be used for renewables. The rural areas are weaker and there's more excitement in looking at them.

I did a project looking at putting one and a half megawatts of wind, up at Orcas Island, up in Washington state. And there was one heck of a lot of excitement trying to get that one and a half megawatts to work on that distribution adder because it was rural, and it was weak, and there were a lot of problems.

You know, all the problems that we didn't see, you can't really, it would be really tough to get that on the rural areas, so --. But the high penetration, that is going to occur. We didn't go out of our way to come up with these numbers, you know, I just took what they took which, actually I thought it was low penetration, in my opinion.

And maybe, looking at what's been going on over the last couple of years, I think probably more affordable phase going in than what was assumed in this market study. And there's also the possibility of more biogas installations.

These were real installations we found at the Inland Empire, on their system. I guess they call them wastewater treatment plants nowadays.

COMMISSIONER GEESMAN: Yeah, but I guess, on that one if you didn't have those dairies at Chino or in that general area you probably wouldn't have had the same predominance of biogas, would you?

MR. ZANINGER: Well, you know what, you wouldn't have the cow pies, you know. However, I heard a couple of weeks ago some of the -- you know, I'm a electrical engineer, so this is a little bit out of my area.

But they were talking about food processing waste like ice cream, where people would pay them to take the ice cream away, and they can make biogas out of whatever the remnants are of when you make ice cream. Which I don't know, but --.

So there's that kind of application as well. And they have the wastewater treatment plants all over the state, so I think there's a lot of application. And those are places where you could make the biogas and burn them and generate electricity with them.

COMMISSIONER GEESMAN: Yeah, I'm trying to visualize other similarly dense load areas.

MR. ZANINGER: Well, first of all, you don't have to look to far, just look down the road from Chino, and keep going. You're going to have that all throughout the Edison service area. Look at PG&E, they're serving a lot of area. So there's a lot more.

And San Diego's got urban area and stuff, so it's -- if you look at urban areas, there's quite a bit of application throughout the state.

COMMISSIONER GEESMAN: Yeah, I, if I'm doing the arithmetic properly that's about four megawatts a square mile.

MR. ZANINGER: Okay.

COMMISSIONER GEESMAN: And what is your ordinary urban area like in terms of load per square mile? San Francisco's probably more concentrated. There's a network system here in Sacramento, so you must have a similar density here, and I know there's one here and in San Diego and San Jose.

But apart from your urban centers --.

MR. ZANINGER: Well, you could look all, the whole peninsula there.

COMMISSIONER GEESMAN: Yeah, good point.

MR. ZANINGER: And I think if you look at electrical you're looking at three to four mile adders, multiple transformer substations, I think there's quite a bit of that.

When I first started doing the study I was calling it the suburban area. And then after I got into it, that's why we call it the mighty grid. Because it really had a lot more load in that area than I was expecting, so --.

COMMISSIONER GEESMAN: Okay, thanks very much.

MR. SIMONS: And we're really going to switch gears now, and start getting into existing bid procurement processes, and Brian Schumacher from the CPUC is going to provide some comments.

MR. SCHUMACHER: Thank you, George. I'm Brian Schumacher from the Energy Division of the

PUC. Thank you, Commissioners, for having the PUC her to make a few comments about the transmission adders issue.

I see that the utilities are prepared to go into some depth on how they are currently implementing the PUC orders for this purpose. And the best way for me to spend my time and add some value in the short time here is we decided I would just review a couple of decision drafts in that area in the PUC pipeline right now for the next Commission meeting. As to how the TRCR transmission reports will be modified, based on a year's experience.

I should again emphasize these are decision drafts, they're out for public comment. And I'll go over their provisions.

This Powerpoint has a few links in it to the decision drafts and to some related reports, and anyone who would like some copies just email me at bds@cpuc, that's boy dog sam, and I can send it to you.

Under the RPS program, the rank order and the selection of the least cost best fit resources must consider the cost of transmission, and so the PUC adopted a method to develop and consider those costs for the 2004 RPS procurement cycle.

The prior -- well, what I should do, despite the fact that utilities will cover this in detail, for the comments on what's to come to make any sense I have a couple of slides summarizing what is the multi-step method to consider the transmission costs that's in effect now.

So, prior to the RPS bid solicitations by the utilities, the utilities request information from potential bidders. Then, with the results of each utility group, the RPS bidders into clusters around substations, typically to identify the network upgrades that might be required.

And they'll estimate the costs, and they'll conduct those studies either directly using ISO study results or their own in-house conceptual studies.

And then each utility files those in the transmission ranking cost report and that's subject to approval of the assigned Commissioner. And once that happens all the bidders are sent that cost report to give them a quantitative feel of the kinds of costs they need to add to their bid and giving them a better likelihood of knowing whether their bid will be accepted.

And with the bids that then come in the IOU's use the cost reports and the ranking method to create the least cost best fit bid ranking.

The bid solicitation, the first one for 2004, required that the utilities file these reports, and they were, as planned, approved by an assigned Commissioner Ruling.

But now, in preparation for the 2005 solicitation there are two ALJ's at the Commission working on related Decisions, and they have released them for public comment, and as I mentioned those drafts are already scheduled for discussion and revision based on the public comments that come in, and hopefully will be adopted in July at the Commission meeting.

The first one, ALJ Terkeurst, who is assigned to the Commission's generic transmission OII, this draft would largely continue the 2004 method, but it would do so, importantly, only for 2005. There is not a plan to continue the method beyond 2005.

The link shown on the screen is to that Decision if you don't have a copy. And you can find it on the PUC website as well.

The companion Decision by ALJ Simon is in the Rulemaking which was opened last year to implement RPS program. This draft Decision would approve the IOU procurement plans that have been submitted, and in this Decision, however, there are two changes from the 2004 plan, which are highlighted in bold.

The bidders may submit bids that have delivery points outside the IOU service territory, and they may submit bids under which they would accept curtailability. The link is to the second Decision by ALJ Simon.

On the first reading it appears there might be a conflict between the two Decisions. There is not, they both allow curtailability as an attribute in the bids. The only aspect of what might have been a part of the Decisions that was not rejected is the allowable percent, a specified number, which was proposed in the workshop report, a five to ten percent figure, simply due to lack of an actual record on that the Commission is deferring any decision about the percent curtailment.

And finally the Commission does intend

to address treating these transmission costs on an integrated basis with other RPS issues, after this procurement cycle this year.

In a little more detail, and I'll move right along. this was the first Decision. The total actual net change in total transmission costs would be the definition of the transmission costs to be considered as added to the bid.

And there are a handful of bullets you can see here. They would no depend on who builds their funds, the upgrades, and brings into consideration the network benefits and displacement of existing generation and lower congestion may be a recognized benefit of upgrades and even further benefits and operating costs if an upgrade is larger than what's immediately needed.

You could, for example, import more economy energy.

Again,k the plans to adopt the numerical standard. We don't know, I don't know of any plans or opinions of the Commissioners to change the proposed Decisions. I know that everyone is still preparing comments. Again, a reminder that this could change.

That link is to the staff workshop, from the February workshops, which is a substantial document. It was attached to a ruling in April, I believe.

A new feature for the 2005 solicitations is that it will include carrying costs, the IOU's must consider the carrying costs of the transmission upgrades as well as their initial capital costs.

Large transmission upgrades. There is concern of course with the multiple small generators and one large expensive upgrade in the Tehachapi CPCN proceedings coming up, there are three of them.

In those proceedings the ALJ may request information to help decide how to resolve this issue.

Things that won't change are the dynamic line readings, nothing is being adopted there. The coincident generation, and the need for the assigned Commissioners to still approve the utilities reports when they file them.

The second draft, I only have one or two slides here. This is ALJ Simon's draft. There are about four requirements.

To summarize, again the overlap between the two Decisions, would allow accepting the bids having delivery points outside the IOU service territory, the additional costs of re-marketing or other costs that utilities pointed out would necessarily be taken into account if the bid had a delivery point outside the service territory.

But they would not consider adding to a bidder the cost of the upgrades to allow delivery through another IOU service territory, unless the bidder proposes delivery after it is already connected in the other IOU service territory.

And finally allowing curtailability without any specific limit on the degree.

I looked at the potential discussion questions and I think the question six was something that had come up in a couple of occasions and meetings and forums that I have been involved in recently.

That is, as appears on the screen, are we approaching the transmission evaluation methods in the right way? The answer is here, that, since there are quite a few different studies going on, and there are as I understand contracts that would be assigned for additional studies, across all the different entities that are involved -- the PUC, the CEC, the ISO, the utilities, the contractors -- to the extent that we can get together and agree on the starting points and the databases and the common assumptions we would all be better off.

Because the studies would be more comparable and provide better direction.

That is the end of the presentation that I have.

COMMISSIONER GEESMAN: Thanks, Brian.

MR. SCHUMACHER: You're welcome. Thank you.

MR. SIMONS: We need to take about a five minute break, so that later on this afternoon Dave Olsen can call in.

(Off the record.)

MR. SIMONS: Okay, let's start. Next is Jorge Chacon.

MR. CHACON: Good afternoon, I'm Jorge Chacon with Southern California Edison.

(unintelligible) . . . the dialogues that were established for developing these Transmission Ranking Cost Reports, request for the additional information, the actual report itself, and the mechanics of developing the reports.

In Decision 0406013 the Decision adopted a methodology for development in consideration of transmission cost. And as Brian indicated, the methodology indicated to include all cost of interconnecting and delivering a generation resource in order to prepare and file the Transmission Ranking Cost Report.

Edison's report was a few weeks late. I ended up having appendicitis, so I couldn't meet the deadline.

COMMISSIONER GEESMAN: Was that accepted as an excuse?

MR. CHACON: Well, I believe so. And the attachment A in the Decision provided the approved methodology.

There are two things that I think are somewhat important, and one is that the direct assigned facilities, otherwise known as Gen-ties, were to be assumed to be internalized into the RPS bid.

And there was a large debate as to what constituted a Gen-tie. So within the Decision there was some language that indicated that, if more than one generation resource utilized the facility, go ahead and develop the cost for it, and in the report indicate whether you felt there was a Gen-tie or not and why. So our report did that.

And the second bullet were the network upgrades, and those were the facilities identified after the point of interconnection, where upgrades to integrate the renewable project were necessary.

The approved methodology itself. It provided estimates of the capital cost, so we were to figure out what transmission upgrades were necessary and then go off and, to the best of our ability under the limited amount of time, develop a cost estimate.

We did this using a unit cost guide. So the estimates are non-binding, they're basically the best information we had by looking at either prior projects or unit cost guides as to what the costs of developing such a transmission upgrade would be.

And we were to reflect additional data into the report. The data was obtained as a result of the decision requiring utilities to go off and request supplemental information. Some of the supplemental information -- well, the request itself translated into a total of nine developers for Edison that submitted supplemental information.

The nine developers had a total of 25 different projects. The total projects were roughly about 6,000 megawatts, and of that amount 110 megawatts was identified to be delivered to San Diego, 160 was identified to be delivered to PG&E, and the rest of them they didn't know. So it was either Edison, San Diego or PG&E.

So we went ahead and rolled the 110 megawatts to San Diego, the 160 to PG&E, and the rest of it we just assumed they stayed at Edison. That's the way we did our report.

The established guidelines themselves. We were to group renewable projects into clusters, and the clusters were to be based on geographical locations. We were to figure out, look at a map and, you know, these are the projects and these are the geographical location and therefore you can treat them as a single point or a single group of renewable resource from which develop a single plant to interconnect them.

We were to assign them a substation interconnection point. In the case of Tehachapi, since there is no substation up there currently that could support that amount of resource, we identified several new conceptual substations, two of which are included in the CPCN application at the PUC.

One of them is near Calsumet (sp), a cement plant known as Calsumet, and another one a mile south of the Monolith Cement Plant -- I believe it's got a different name now, I don't know what they call it.

And we were supposed to use previously conducted conceptual studies. Edison had a number of these, we did a number of them for the wind community, we submitted a number of these for compliance with Senate Bill 1038.

We then performed an additional one on March 19th, as far as complying with an ALJ ruling. And then we had other comparable studies, like the PUC report to the Legislature, and the CEC report. So we utilized all hose conceptual studies so that we would not reinvent the wheel and use the information that was currently available as best we can.

And we were supposed to develop a cost estimate to provide for the full deliverability of the renewable resource, so we went ahead and did that.

COMMISSIONER GEESMAN: Deliverability to where?

MR. CHACON: Uh, to the load center.

COMMISSIONER GEESMAN: Okay.

MR. CHACON: Yes. And then the last bullet, for those particular projects that had undertaken an actual generation interconnection through the ISO interconnection process, we were to modify the conceptual costs to be aligned with that of system impact study and a facility study.

We were supposed to look at identifying transmission network upgrades and capital costs expected to be needed for each cluster at various levels. So we were looking at what was deemed a level one, which was the available capacity with no upgrade and consequently no transmission cost.

A level two was the next upgrade that would be necessary. Identify the megawatt capacity for that upgrade and it's corresponding cost. And then level three, four and five and beyond it was a continuation, or a phased expansion program, so that you can integrate the full potential.

We were to look at, including non-binding cost estimates as I mentioned, for all levels, except level one, presumably there would be no cost for that.

We were to identify cost estimates for delivering into another transmission system, and we did that for the 160 megawatts to PG&E and the 110 to San Diego.

The request for additional information itself. We, being the utility, did not know where renewable resources are going to be geographically located, so we submitted a request to the various renewable developers asking for them to identify the generation output of the facility, the number and size of individual units, the expected first point of interconnection, expected in-service date, the type of technology, those type of things, so that we can try and line this thing up as best we could with the system impact study type of study approach.

And the RPS bidding information, the intended buyer, so that we can figure out if the output is going to go to San Diego or PG&E or Edison. And as I mentioned, a very small amount of individuals indicated that they wanted to sell to San Diego or to PG&E.

The Transmission Ranking Cost Report, I brought my copy. I was reading it again to refresh myself, since it's been almost a year since we filed it, on July 7th it'll be a year.k

We developed it in accordance with the approved methodology. The renewable resources were grouped into 13 clusters. Six of the clusters were for wind generation located in Los Angeles and Kern Counties; five of the clusters were geothermal, solar and wind located in San Bernardino and Mono Counties; two clusters were for geothermal and wind in Imperial and Riverside Counties.

And I did not put the total here, it's quite a bit of renewable resource. Both renewable and non-renewable generation projects proceeding through the interconnection via the ISO or for interconnection process were included into the starting case.

The transmission projects identified as part of the annual expansion program to serve load, joint load demand, were included into the starting case, if it generally supported the project, if there was a support for the project through the ISO.

Some of the projects that were included have yet to be approved, but the consensus is that the projects are going to be supported, so we went ahead and included some of those.

Other transmission projects identified through other studies were included if approval was anticipated. So if we did a generation interconnection project for a non-renewable, and we identified the need to upgrade the network and the ISO seemed to be in line with it, we would include it as far as this study was concerned.

The mechanics for developing the Transmission Ranking Cost Report. We performed preliminary power flow sensitivity studies. We examined base case conditions for, I believe it was heavy summer.

In the case of wind we looked at both heavy summer and some light spring, but very little. It was a limited set of single outage conditions, so we didn't do a full scale system impact study quality assessment.

We did not perform the detailed studies that were necessary, that would be in line with the system impact study. Those studies would include base case and single contingency power flow that were limited in nature.

So they weren't a full, developed reviewed and approved case. It was just taking what we previously knew and then adding on top of it the renewable resource.

The power flow studies did not consider a loss of two transmission facilities. That must be done in accordance with WECC criteria. The power flow studies arbitrarily assume the use of a special protection scheme.

If they define the loss of one facility, there was an identified overload. We don't know at this point whether such an assumption was valid. There's a lot of work that goes behind a special protection scheme study to determine whether it would even be approvable by the WECC.

There was no transient stability conducted, there was no short circuit duty conducted, and as a result we had no indication of whether either additional dynamic voltage support would be required for transient stability.

We had no indication of how many breakers if any needed to be replaced.

And lastly there was no post transient voltage studies performed.

The study is limited, in addition to these in nature. The limitations include, we identified eight of them in our report. They include the fact that the exact locations are still somewhat nebulous, although some projects identified exact locations, many of them did not.

The report was not consistent with the interconnection process, and therefore those studies still have to be done.

The detail system impact studies need to be performed to fully evaluate the impact on the electrical system.

Substation site review needs to be performed for those locations where a new substation would be required. As mentioned, we identified two in the Tehachapi area, and that was it.

Detour right of way needs to be undertaken to figure out if in fact the right of way is available to construct a new transmission line if you had to.

We did some environmental, not as part of this study, but as part of previous studies. So to the extent we can rule out certain routes because of a fatal flaw or a significant impact to the core resource or to the environment in general we ruled out those routes.

But there were certain routes in the study that came about that, we'd never done that because there was a new location identified.

And the last thing was that the cost estimates at the end were standard off the shelf. Those cost estimates, in and of themselves, need to be modified. The cost of cement and steel and everything else has grown exponentially as the demand in China increases. So we know our cost estimates are not in line with what they really ought to be.

The limited conceptual studies reflected the same approach, using conducting detail system impact study. The reason for doing this was that the generators themselves are going to have to do a system impact study, and therefore it would be prudent to figure out what facilities would ultimately be identified, by using a method that's similar in nature.

There was a lot of controversy with regard to that, and I"m sure there's people here that probably don't like it, but the decision was made to go ahead and do that.

The approach allowed SCE to identify any development level. That is, input generation, when you have an overload, putting in a facility upgrade and increase the generation some more. Basically a lot of it has to do with phased expansion.

Transmission upgrades identified through the limited conceptual studies were estimated, I've already mentioned that, using unit cost guides. We published the report on July 7th, and the last bullet is that the new cycle has demands, as covered by Brian Schumacher.

COMMISSIONER GEESMAN: Jorge, you didn't do a 2004 RPS solicitation. So how did have you used the TRCR to date?

MR. CHACON: You know, I don't work for the QF department, but my general knowledge is that there were some bids, and I don't know how the bids were obtained. I'd be incorrect to tell you something right now, because I don't know how they were obtained.

But the information in this report was used to compare those bids to figure out which were the more likely bids to be developed and to have a holistic cost to add the transmission component into the bid cost.

COMMISSIONER GEESMAN: And have you used the TRCR for the RFO that you have outstanding now, the all source RFO?

MR. CHACON: The intent is to use the Transmission Ranking Cost Report. As mentioned, we are undertaking the new 2005 and I believe we're going to be using that report.

COMMISSIONER GEESMAN: I'm not talking about the renewable soliciting for '05, but you've got an RFO out for new generation of all sources. Are you using it in that solicitation?

MR. CHACON: No, we don't -- well, let me take that back. For those generation resources that are non-renewable for which we have an RFO, I think the requirement is to have them apply through the interconnection process and then we can fully evaluate what facilities would be necessary.

So, while I'm not the planner for that, I believe the approach is to have them go through the full impact study phase and evaluate the project on a holistic basis to make sure we sort the right one.

We want to make sure we capture

generation impacts on circuit breakers, which we didn't do here. To us it's a big concern.

COMMISSIONER GEESMAN: Okay. Any questions for Jorge? Thanks a lot for being here.

MR. SIMONS: Okay, we'll head up north, as it were, and Chifong Thomas will talk about PG&E's TRCR report.

MS. THOMAS: I'm Chifong Thomas, I'm from the transmission side of PG&E. So to the extent you have any questions about the procurement because of the order of 2004, we're not really communicating with our procurement side.

So there's Howard Flash and Charley Coast over here, so I may have to defer questions to them. Or if they think I'm saying something that's completely wrong they will have to jump up and correct me.

So, anyway, here's the Transmission Ranking Cost Report, the methodology. First off, here's the topics we'll be covering today.

And first off is the objectives, the limitations, some overview in how we develop it and how we estimate congestion, and basically we use some proxy facilities, and how we determine the generation levels.

The objective for the methodology is of course to decide on the least cost best fit selection of facilities. And it is actually an alternative to cost estimate from the ISO interconnection process.

Because the best thing would be that each developer would come in with a completed system impact study and facility study and go through a process and give us a cost estimate for the bid.

However, we realize that is not really possible, and so in order to not hold up the process we figure that it would be a better idea to just give everybody some information so they will be able to structure the bids accordingly.

And so the process, basically, we try to adhere to all FERC rules governing generation and connection and open access. And the reason for doing that is actually for the protection of the ratepayers as well as the developers.

Because generation and connection is governed by FERC rules, and so it's a transmission capacity, availability and cost estimation and so on.

And so if we were to artificially change the process so it's not as closely aligned as possible, then we could come up with divergence problem later on and it really doesn't serve any useful purpose for the utility to go in and wasting time negotiating with somebody and then later on find out the project isn't really feasible because when they did finally do an interconnection process and the cost come out to be a lot higher. Or the fact is they're not really the least cost to start out with.

And then, in the case of the developer, they're also wasting time negotiating with us, and everybody lose because now the whole process is going to be drag out.

So the whole idea was that it would be able to provide pre-bid information, which is really similar to what the CEC is doing right now, that would be effective for people structuring a bid, if they see that the transmission is not really available in certain places maybe they would say not -- during the time period or go somewhere else to better places.

So it benefits both the developers and the ratepayers. And also, for the, this is only for the short list selection. It is not for awarding winning bidders or anything else. The winning bidders, once it goes through the short list, it still goes through a negotiating process.

And once the contract is awarded, or even before that, they must go through the interconnection process through the ISO.

Now here are some challenges as to doing it this way. The transmission planning process, for that to work, is that we must have a level configuration, we must know the specific information, the location sizes, characteristics of each low and each generator.

So that it's not just one particular new generator or two generators, it's the whole combination at the end, what's the end result of all the generators that would be online at that time and what are they going to be generating or not.

But then, before the winning bidders are selected we can probably guess at what the network configuration is probably going to be like. We have approved projects and we can guess at what needs to be done afterwards.

The low forecast, we can probably guess

at that also. But then now we don't have any generator specific information and that becomes a challenge because now we don't have one part of the information that's necessary to determine what are the system impacts ultimately, and that drives what the transmission decision's going to be.

So we don't want to hold up the process, we obviously couldn't go ahead and do all the studies necessary without knowing what the winning bidders are, so we had to make some changes.

And so, here's a method we can use, but it's very limited, it has a lot of limitations. And like Jorge said, it's based on limited information, the cost information was only for bid selection, and we used proxy facilities, which I'll explain a little bit later, on what that is.

And no computer simulations. So instead of having like Edison is doing, they actually run some cases, we run very few cases. We did not do any fuel check for engineering in my mental assessment.

So the only thing we did was that we go to the map and we say, hmm, this line goes through here, it looks like urban. But then we really didn't do any other checking other than that.

But then we often dealt with information with the off the shelf study available. So any study we've done up to that point in time we go back and take a look so we don't have to go back and say gee, this is correct, or that's not correct.

So we don't reinvent the wheel, we use all existing information as much as possible.

So in order to do this we have separated out the cost responsibility. As Jorge had said, the direct assignment cost, or Gen-tie, is to be included in the bid price.

But then if there were any places that say, for example, there were some generators that would identify the close proximity and they indicate to us that they would be willing to share the Gen-tie cost, then they would tell us, you know, how much to be shared and we, in the bid evaluation we take that into account, if they were both short listed.

Wheeling charges in non-participating transmission owner system, say for example they were located in Oregon and they want to bring the power into the PG&E system the wheeling charges that Pacificorp would charge them would be also included in the bid price.

The cost responsibility for the ratepayers are the network upgrades, which is from the first point in the connection towards the load. The transmission adder at the cost would be developed from the ISO interconnection process, that is they can also, if they had a completed system impact study or facility study and bring that cost estimate and submit that with the bid.

Otherwise we will use the Transmission Ranking Cost Report that we develop.

COMMISSIONER GEESMAN: Chifong, do you know if many of your bidders did have completed system impact studies?

MS. THOMAS: Only maybe one, because most of them don't have a completed report, and so it's, the idea I think is the fact that we'll take a look at that and see where would be a good place, and actually it did happen that way.

And the 2004 solicitation is in the bottom here, well, it's not exactly, it wasn't a link in the presentation, but you can go to the PG&E website and follow that and you can gather information on it.

Oh, before I say this, because the

utility were going to, the PUC want us to put in doing study assuming that the developer would be selling to PG&E or the developer would be selling to Edison.

So what we had done was, we identified the clusters from the information, both from the CEC report, the RRDR and the PRRA that was sent out last year.

And also we take a look at the information from the developers themselves, and we identify certain substations that we think they will be bidding to, and that would be how we evaluate them.

COMMISSIONER GEESMAN: And how many substations were there?

MS. THOMAS: We identified seven clusters, and the study would be done based on an on peak case and a off peak case. And we had developed four scenarios, on peak and off peak for selling to PG&E, and on peak and off peak for selling to Edison and to San Diego.

COMMISSIONER GEESMAN: Right.

MS. THOMAS: So there were actually four tables in the Transmission Ranking Cost Report that we submitted to the PUC. However, for the protocol we only listed the two tables for them to sell to PG&E. In fact most of the bidders who come in will sell to all three utilities, so --

COMMISSIONER GEESMAN: Right.

MS. THOMAS: -- it was, we would just direct them to the other reports.

So in here is the bid submittal. We would do a first bid ranking based on thee factors other than transmission. So in the protocol the bidder has a choice of, actually a bidder can submit a whole year's worth of generation profile, if by hour. And so we have that.

And we have other information, such as price and some other information which I don't quite remember off hand. So what the procurement side would do, they would rank all these bids, first based on all this information, and no transmission yet.

And then after that they would give the transmission side a list of bidders, based on the first ranking. So according to the methodology with the Decision at the PUC we would assign the first level of transmission, the cheapest level of transmission, to the bidder with the best portfolio, with the best fit other than transmission.

In other words, if they rank high in the other factors they would get the cheapest transmission cost, and then so on and so on. And of course the transmission adder would be developed from there, and then you used either the Transmission Ranking Cost Report or the system impact study and facility study cost.

Then after we do a second ranking, then we went to a short list. And then there were other considerations, which is they would contact the bidder and the negotiation would go on and then we'd have an RFP result. But my responsibility really ends after we hand over the transmission ranking, the second ranking.

Here's how it goes. What we do first is the utility would send out a solicitation for information, which is what we did. I think in 2004 it was somewhere in February.

And then we also send one out this year in March, March 18 I believe. And then we request information from bidders that is non-binding, so they can tell us how many megawatts they expect and where.

We also take information from the public information such as the CEC's report, and then we form the clusters. Last year we had seven clusters and I think this year we're probably going to double that.

And then we would develop, of course we'd go to the part where we develop the transmission ranking cost. And then we use either a ISO approved base case or if not we'll pick out a WECC base case that's approved.

We put all the generators that are already in the ISO, in the connection cue. And also the transmission associated with interconnecting that generator.

Then we also come up with other readily available studies. Then we would develop these tables, and then we send it over to stakeholder comment, and then the utility would publish the Transmission Ranking Cost Report.

And then of course alternatively the bidder can put in their own network upgrade costs in the ISO process. And then we go through a second ranking and then we go through the results.

Now, the next thing I'm going to talk about is how we developed this. So the first input is that we go pick the generation project in the ISO interconnection cue. We put in the base case that's approved.

Then the second input would be from the public information that the CEC report came up with, and then also from the renewable information from potential bidders.

And then we group them into clusters. And then we go to each cluster and we take a look at the loading of the transmission lines. If the loading were higher than 80 percent of normal rating and the load increases after the additional renewable --.

So two things had to happen. It had to be heavy loaded and the loading would increase after the addition of renewables for that cluster. Then we would make that count.

COMMISSIONER GEESMAN: And that's taken at peak?

MS. THOMAS: Both peak and off peak. Because actually we use two cases, summer peak and then a winter off peak.

COMMISSIONER GEESMAN: Okay. So high and low for the year?

MS. THOMAS: Yes. We would like to use more cases, except that we jus don't have that much manpower to do that work.

COMMISSIONER GEESMAN: Okay.

MS. THOMAS: Then when that happens, when the facility is flagged, we would look at a proxy transmission cost for adding the renewable generation for that cluster.

And after we add that proxy facility we would increase the generation again at that cluster, until you hit the next 80 percent and so on.

So we try to come up with three levels, but some of them we don't really need to because the place might have so much transmission capacity that you hit 1,000 megawatts and there's probably no point in adding more levels by that time.

So we would go to the second, after that it would go to a second ranking.

Okay, let's talk about why we do 80 percent normal. Because for each cluster we say 80 percent normal, and then the loading you have to increase up the additional renewables. And by the way, when we add renewables we have to decrease the generation somewhere.

So what we had done is we try to increase the oil and gas. The non-renewables from the oldest units first. And for the Bay Area and other places that have loading problems, what we did was we did not increase it below what the ISO required would be for the RMS requirements.

So if you look at at typical transmission facility, the typical emergency rating of a transmission facility, for PG&E anyway, is somewhere between 15 to 25 percent higher than a normal facility.

So for this purpose let's assume 120 percent, which is 20 percent higher. So suppose this is a hypothetical system and if I load everything, all my transmission line here to be 100 megawatts and assume this is normal rating, and the emergency rating is 120 megawatts.

And so now if I put in a generator, and this is load to 100 megawatts, which is 100 percent of the rating, if I lose aline, and assuming that the remaining two lines would pick up all the loading, so now I'm at 150 percent of the loading.

Now, recalling that my emergency rating is 120 megawatts, now if I would have loaded the transmission line to 100 megawatts, which is now equal to 100 percent of my rating, I would have been overloading my system after N-1.

So for this example, if I were to do this, I don't want to do that, so during my normal during my normal condition I would back down this loading to less than 100 percent.

So to do some calculation, you'd just be taking your 120 percent, which is your emergency rating, divided by the loading you expect, and then multiply by 100 megawatts, which is your normal rating, and then I give my 80 percent.

And so this is a really rough cut and we'll look at what could be going on with how we would evaluate a system without really going back and doing a whole bunch of studies, and this is the reason why we think we want to err on the little bit conservative, because we don't really know exactly what's going on.

And also the fact that we are doing it one cluster at a time. For example, if I had this cluster I'd say well, okay, I'm going to load this up to a certain percentage, 80 percent, and I'm good.

But then suppose I have another generator here, and this generator could very will come in and when both of them come in I would have a problem that I did not foresee by only looking at one cluster at a time.

And this is the limitation of this methodology that we need to be very careful about the application.

So once we did that --

COMMISSIONER GEESMAN: Let me ask you something about that point, Chifong. Does that problem or potential problem get aggravated as the number of clusters go up?

MS. THOMAS: It would, but the idea is that after they come in and basically just give you a broad view of things, and once you look at it and -- that's why in the end yo still have to go through the system impact study, because that's where the back stop is, because if we missed anything here we may be choosing the wrong resource.

But the system will still be protected at the end.

COMMISSIONER GEESMAN: And all you used this process for is ranking it, before you then go to your second level of evaluation?

MS. THOMAS: That's correct. This is actually for short list. Obviously we couldn't, they couldn't be negotiating for anybody who comes in the door, so wee need to rank them and figure out who should go first.

COMMISSIONER GEESMAN: Okay.

MS. THOMAS: So this is where we are and --. And here, the proxy for surges. When we hit 80 percent what we will do is see what is the level of that facility that's being congested.

And if it's less than 100 megawatts addition of the renewables, basically that's the reason why when we went and asked for information from the bidders it's so we can assess how big this cluster could be.

If I get baseline information the only potential bidder would be about 200 megawatts, and then obviously we probably don't want to build a 500 KV line, if certain things overload it.

On the other hand, if you have a 230 KV line that's overloaded, or a 60 KV line that's overloaded, and you look at a substation, and the two substation had no 60 KV busses, or one of them didn't have a 60 KV buss, then it doesn't make any sense to go in and build a 60 KV line, because now you'd be talking about transformers and more buss structures and everything.

So we try to minimize the cost as much as possible. And of course, the other thing is if you have 500 KV lines overloaded, we don't just automatically build another 500 KV line. It really depends on how much generation do we expect from the bidders from that cluster.

So again, we add enough generation, we go to 80 percent. Level one, we put in the transmission upgrade, and then level two and so on. And after all this we also compare with, when we hit the limit we compare with our five year plan to see if there's anything else in the horizon that had not been approved that may be a duplicate or maybe defer or we may need it anyway, so that would also go into consideration here.

COMMISSIONER GEESMAN: And how does that consideration work?

MS. THOMAS: Usually if we think that a similar transmission project is needed, say in 2020, which -- we don't go out that far anyway, but --

COMMISSIONER GEESMAN: Yeah, just call it year three of your five year plan.

MS. THOMAS: Okay. And then suppose we put in this renewable and it looks like all of a sudden we need this in advance need of this transmission facility. And so we would be taking that into account by saying okay, instead of being the whole capital cost to be included in the TRC, then maybe it would just be the advancement cost, the cost to advance the facility.

But so far we haven't had to make that decision because all the transmission addition that's needed was not covered in our five year plan.

COMMISSIONER GEESMAN: It was outside your five year plan.

MS. THOMAS: Right, right. And also too that, since all the renewables are not really inside the load center, so that's another thing that -- if it's inside the load center there's certain things that you can say, that certain lines would be needed or not needed, and some line could be advanced and some line could be deferred.

But what we try and do in this case since there is all in the load center, anything within the load center that was overloaded or congested we would discount that, because that is not part of the deal.

COMMISSIONER GEESMAN: And where do you

define your load center to be geographically?

MS. THOMAS: Roughly the Bay Area nine counties.

COMMISSIONER GEESMAN: Okay.

MS. THOMAS: So here's a summary. Again, we're doing this because of least cost best fit, and we need to, it's an alternative to cost estimates for the ISO interconnection process.

And we need to adhere to all FERC rules governing generation and connection, and basically it's pre-bid information, we try to get the maximum amount of information out there possible for people to structure their bid and say --.

For example, if they have a generator that could be pretty well dispatchable, or that could be controlled, then if they see that at the peak there is plenty of transmission capacity available, say 100 megawatts, with no transmission addition required, but then during off peak only 50 megawatts is available, then maybe it can fit in during the peak time 100 megawatts and fit in 50 megawatts for off peak.

And so when the bid is structured that way you can sort of avoid or minimize the transmission impact for this process.

And so, again, it's only for bid ranking purposes, and one of the aim is to limit the ratepayer risk. Questions?

COMMISSIONER GEESMAN: I know the intent is to limit the ratepayer risk. How effectively do you think it does that?

MS. THOMAS: Well, so far, of course we've only had one solicitation. So ar people have been bidding into the area where, the first level had no transmission cost, and they've been staying below that.

And so --

COMMISSIONER GEESMAN: Of course, that's before they've done their system impact studies. So --

MS. THOMAS: Exactly, before we've done it, before they've done it. But I would think that if we were to go to another location that we already know this is going to be a problem, when they do a system impact study they would probably see more problems.

COMMISSIONER GEESMAN: But the ratepayer risk will ultimately be determined by whatever that system impact study shows, won't it?

MS. THOMAS: That's true. If we were to

come up with something that they don't know the system, and not knowing any information at all, so the tendency would be to go where all the other information would be available. And so they would tend to, people would tend to locate somewhere that probably not be less useful to the ratepayers.

COMMISSIONER GEESMAN: I see.

MS. THOMAS: And the other thing too is that if there are certain things they can do in the negotiation also to, in the other consideration, that could also avoid some of this.

COMMISSIONER GEESMAN: What do you mean?

MS. THOMAS: For example, if a congestion, if there is congestion management by the ISO on the interzonal phase, congestion, then if they were to come up and say that they would pick up the congestion cost --

COMMISSIONER GEESMAN: Okay.

MS. THOMAS: -- then that's another way.

COMMISSIONER GEESMAN: Okay, so there are various terms and conditions that can be negotiated into the contract to get around some of these problems?

MS. THOMAS: Oh yes, but then I'm not

the person who is negotiating contracts, so --.

COMMISSIONER GEESMAN: But they talk to you about how best to mitigate your congestion problems?

MS. THOMAS: Well, what my charge is, that a procurement group would give me a problem to solve. So this is the problem, solution.

COMMISSIONER GEESMAN: I follow. Thanks very much for being here, I appreciate it very much.

MR. SIMONS: So we need to check to see if Joe Kloberdanz --? Okay, great. Do you want to come up here and talk --? That's fine with me.

MR. KLOBERDANZ: Good afternoon Commissioners, Advisers, staff and other guests. I'm Joe Kloberdanz with San Diego Gas and Electric.

Many of the speakers you've been hearing today are engineers, and I'm not. So if that little bit of diversity doesn't trouble you I'll continue.

I want to start off -- I have about seven points, I've been told I have about 20 minutes. I think I can do this in ten.

I want to start off by saying there's

been some fine work done here by the staff and the consultants to put together a comprehensive approach to asses the state's ability to meet the RPS goals.

I don't have the ability today and with the time I've had with the documents to fully assess all of the merits and details of it, but it looks like a lot of fine work has gone into this and it looks like a responsible approach has been taken to it.

COMMISSIONER GEESMAN: You know, if anybody within your organization wants to forward more detailed comments, we have extended the period for written comments to the 22nd.

MR. KLOBERDANZ: Yes, I was here to hear that this morning, thank you, and I will try to encourage a more detailed review of this.

One of the problems I have is that our transmission folks who should be paying some attention to this in the past week are pretty busy with some RPS related work.

COMMISSIONER GEESMAN: I was going to say, they've got their hands full.

MR. KLOBERDANZ: So I apologize for that, but we will attempt to do that, and I thank you for the opportunity.

We do appreciate the effort, and I think there's an intention here to periodically update that assessment as well, and we think that's a good idea.

And we also, I'm going to stick my neck out here a little bit and say I think it's reasonable that the IOU's provide some of the kinds of assistance that Ron Davis and others have suggested have been helpful to further perfect this approach that they're using.

There are things we have done, provided them, and I think further things we can provide them, or updates at least, and we should do that, we should make it a better process as --

COMMISSIONER GEESMAN: Let me try and one up you a bit on that one, Joe, because I think --

MR. KLOBERDANZ: You're not going to take me down a confidentiality path right now --

COMMISSIONER GEESMAN: No no no. If this is a valuable tool, and I don't know if it is or not. It seems like it has certain attributes that are attractive from my perspective, but if it is to be a valuable tool I think that what would be in the Commission's best interest and the state's best interest is to try to transfer that tool into the utility sector.

And you can determine if it is a valuable tool and if it is something that you think your company should make use of.

And I say that with respect to each of the utilities. If you do se some potential value there, I think our PIER program should in fact assist you in adapting that tool to better meet your needs.

MR. KLOBERDANZ: That actually goes to the next point that I want to touch on. I think it's valuable that it be assessed by someone in the state, on a statewide basis, how we're doing with respect to progress on the RPS goals, and what the potential is, what the capability is out there.

And among other things, we have considered whether to accelerate the goal. And some of us have voluntarily said we'll try to do that, best efforts. I suppose there is legislation that is considering that.

There is also recognition in the legislation that put the RPS in place that, should there be good reasons why we can't achieve the goal in the time frame stated that there are opportunities to achieve a different goal. So we need to keep an eye on it as we go forward.

That's the primary value I see in it. We have in place -- and my colleagues of PG&E and Edison have just described it to some extent, Brian described it from the PUC as well -- we have in place the methodology that we're using right now to perform the more bid-specific kinds of assessments that we need to make as we go along.

And that's a different assessment. It's what do you actually have to do now that you've got this bid in hand, and it may be a good price but it may not be in the right place. But even though it's not in the right place the transmission may not be so expensive that it's not still a good price when you add it all in.

I didn't say that very well, but you know what I mean.

COMMISSIONER GEESMAN: I know what you mean, and I guess the unfortunate thing I think is that we follow, the RPS program follows this model that forces each of the three utilities to look at things separately, and we embrace this metaphor of basically bringing bushels of apples from the field to the barn.

And I'm not certain electricity best works that way. I think electricity provides us with a lot more flexibility than the way in which our institutional thinking has framed the RPS program, right now would allow for.

MR. KLOBERDANZ: I see your point. I think the term, the term I think of for what you've just described is deliverability.

COMMISSIONER GEESMAN: Yeah.

MR. KLOBERDANZ: And I think we're starting to realize that there are ways to look at deliverability that aren't all bring one bushel, this bushel of apples to this barn. It doesn't necessarily have to work that way.

There is a decision which Brian Schumacher did not fully describe, but it's pending before the PUC, which I think would actually tell us to, you know, lighten up a little bit on that issue.

So I think we're going to get a chance to, for lack of a better word, experiment with that a little bit, and see what that means.

COMMISSIONER GEESMAN: Well, and I think

that, we've recently had a contractor report, Ryan Wiser and Kevin Porter, that suggests we ought to lighten up a lot. And I'm hopeful that, as the full CPUC considers this issue in their decision that they pay careful attention to that report. Because I'd rather see a lot than a little.

MR. KLOBERDANZ: We also have the ISO and WECC and those kinds of things to consider, so we're not at liberty to try and do this unilaterally, even if we were inclined to.

COMMISSIONER GEESMAN: That's absolutely the case.

MR. KLOBERDANZ: But no, I hear that point, and I think we're going to get the opportunity to experiment with that a little more very soon.

But the reason, one of the reasons I don't need to describe how we do least cost best fit to you is that we were under the same directions, from the same Commission. And given a good utility practice and good engineering practice I suspect our people did about the same, it sounded awfully familiar.

And if it wasn't exactly the same it was very close. And I know there has been, of necessity there has been some interaction between the utilities for those bids that cross into somebody else's barn so to speak.

COMMISSIONER GEESMAN: My impression though is that what appears to be emerging from the solicitation process are bids that originated in the contracting utilities service territory as opposed to bids which effectively crossed the state, or transcend utility service territory boundaries.

MR. KLOBERDANZ: I suspect, I don't know the full state of the information that's available, frankly, on the 2004 solicitations, which are hopefully now coming to conclusion. I think PG&E has filed some of its contracts, we hope to do so soon.

I believe there has been some of both. There has been a lot of in-service territory and there has been some cross-boundary as well. I think.

COMMISSIONER GEESMAN: Okay.

MR. KLOBERDANZ: And I think the filings will have enough information in them that you'll be able to see that as the utilities bring those filings forward. I think.

COMMISSIONER GEESMAN: Okay. I've not seen it yet, and I'm only privy to that information that is public.

MR. KLOBERDANZ: And I'm sensitive to that, I think there's enough -- I shouldn't speak for PG&E -- but I think there's enough in their filing that you can tell.

But I think that we've already had some opportunities to work with that. I know that when we did our Transmission Ranking Cost Report that we're using for the current procurement round that we did I believe 11 clusters for our service area.

We're just one little corner of the state. I'm fond of that corner, but it's just a little corner. We had two that dealt with border issues, of those 11, and nine within our service area. So it was a pretty healthy assessment.

We're just now getting the requests in for the next one. And our people are, they've gotten those in and they're scrambling to put them together, we have a tight deadline.

I think the point I wanted to make here is that right now there are two things in existence. There is what the staff and consultants have described to us today, and there is the Transmission Ranking Cost Report and it's utilization in least cost best fit that's already in place in a PUC directive.

I'm not saying either one of them is superior. I'm not saying that you have to do one or the other. I'm saying they both have their role. As I see them, as I look at them right now, both have an important role. And you don't have to make either one of them do the other role.

COMMISSIONER GEESMAN: I think that's right.

MR. KLOBERDANZ: I'll stop on that, but that was my point.

One thing I wanted to mention, when I looked at the draft consultant report -- and I don't mean to be picky here, but -- there was a conclusion that sounded, read something like "85 percent of our RPS needs could be met without any significant transmission".

And I thought, that's a little scary. I wish it were true. I don't think it's true in my service area, but that's not really what the report says though, as I understand it now.

The report says something like "after you do a number of upgrades we already know we need to do, and if all of the bids come in optimizing their location, and presumably we would try to give some signal to do that, then you might get 85 percent with very little transmission."

It's important -- you've been a really strong advocate of getting transmission built when it was needed and where it was needed, Commissioner, and I want to thank you for that. We've had a little bit of good luck in San Diego lately.

We've got a new 230 KV line energized, a couple of months ago. And we got another one approved yesterday. And at SDG&E we're grateful for everybody who supports that. There are people who had to vote for it, there are people who have been providing a lot of moral support. We appreciate all of that.

There's going to be a lot more needed, whether it's for renewables or other purposes. And I just want to ask you to keep paying attention to that, we appreciate that.

COMMISSIONER GEESMAN: Yeah, I had a similar first reaction to that conclusion of the report. Actually, the way it occurred to me was that it had been written before the Supreme

Court's recent decision to outlaw medical marijuana, but as I listed to Ron explain it in more detail today I think I better understood it, and I think I've been misinterpreting it.

MR. KLOBERDANZ: Well, it certainly had a shock effect on me, and I do understand it now. So it's not meant as a criticism, but an observation.

It is possible that, as I mentioned a moment ago, that bidders may not bid optimal locations, even if they get the signal. And the Transmission Ranking Cost Report was really designed to meet a couple of key needs, and they're important needs of the generation developers.

One is the need to have some kind of an idea about transmission costs without occurring the cost and time of going through the ISO's process first and having to guess at the location. I understand that.

And the second important need I think it meant is to send those signals so that bidders have time, to the extent they have options about location, they have time to optimize the location they can deal with based on whatever they've got going for their projects, whatever they've done so far on their projects.

That's valuable. And, but bidders still may not be able to locate optimally. But you could get a bid that is not optimally located, as I mentioned earlier, and the transmission price, when added in, still makes it a good deal for customers.

And if that's the case we would want to be able to go ahead and build that transmission.

COMMISSIONER GEESMAN: Well, I guess one of the questions I have about this TRCR process -- how many clusters did you say you had?

MR. KLOBERDANZ: I believe we had 11 last time. The one they're working on right now, I don't know yet how many.

COMMISSIONER GEESMAN: One of the problems I have with the transmission planning process is the, what I regard as the contrived level of precision contributable to numbers that seem to be calculated out to an incredible number of decimal points.

Now, of your clusters and the costs that you attributed to them, how much of those have bounced around the next time they do the analysis?

And I think of your system as quite a bit simpler than either of the two of your neighbors. So I'm not certain what we're capturing with the level of detail we're resorting to or relying on, to serve a very worthy goal.

I don't have any dispute with the need in some simplistic fashion to rank our bids, but I'm just a little skeptical as to the quality and the stability of the information that we're using.

MR. KLOBERDANZ: As I talk to our transmission planners, they tell me that if you look at something one year and then look at it a year later you could have a situation that's different, you're going to have a situation that's different, that's almost certain.

Is it different enough that you would build a different solution? Or perhaps build a solution where a year ago you didn't need one, that's what has to be looked at.

COMMISSIONER GEESMAN: But if you're looking at a range of perspective 10 or 20 year contracts, and you're ranking them based on today's snapshot, which you know is going to change, you don't know how it's going to change but you know it's going to change before you go through the same process 12 months from now, exactly what is it that you gained and have you potentially lost an opportunity with somebody ranked in that lower basket of bids, based on today's snapshot, that next year might have been in an upper basked of bids?

MR. KLOBERDANZ: I think the stuff that's close in, it isn't going to vary a whole lot. But we don't get a lot of that. We have an area of potential wind development that's been well identified by this Commission and other sources in our service area.

And it's right along a six lane freeway. But there's no load there. In fact there's no transmission there to speak of. So even though it's in our service area it's no always easy.

Whereas if you could put that same resource a half a mile or a quarter mile from my office it would be a lot different.

COMMISSIONER GEESMAN: And I have an easier time conceptually thinking about your system than I do either the Edison or the PG&E system. And I have to confess, most of my comments are really based on our larger systems.

MR. KLOBERDANZ: Okay. Well, we'll have

to get you down there more often. One thing I wanted to mention, there was a lot of cost about LCOE, Levelized Cost Of Energy, and I think it's good that they took a good hard honest look at that.

Bids will determine the actual levelized cost of energy of course, over time, and as we go along I think it's important that as we go along we incorporate that as a reality check and kind of updating the database so to speak that we're using to make this statewide assessment.

And it's not all that clear to me, for example, that bidders will always bid at 16 percent ROE. I wouldn't blame them if they didn't always stick to that. But, just as an example.

COMMISSIONER GEESMAN: Yeah, that's a running dialogue that George Simons will tell you we've had over the last several years.

MR. KLOBERDANZ: And that's not a criticism of what the staff or the consultant did. You've got to make some assumptions somewhere along the --

COMMISSIONER GEESMAN: Yeah, I don't think they had a better way to do it.

MR. KLOBERDANZ: No, and I'm not

suggesting that, it's just, there's probably some reality checks to be introduced somewhere along the way. I'm not sure exactly.

COMMISSIONER GEESMAN: There's also likely to be a fair amount of economic rent in some of the bids that get picked up, particularly in these early solicitations. I think if we had a west-wide solicitation system, or a RECs trading market we might have bids a little more closely correlated with costs.

MR. KLOBERDANZ: I would agree with that, sure. Just a small detail, the wind capacity factor -- there was an alarm going off and I couldn't hear the actual second attempt at an answer -- but it's still not clear to me that we have that one nailed down.

And since we're talking about a lot of that over time it's probably important to get that nailed down. My understanding is that in different parts, different wind resources, you get different typical capacity factors, and it's probably wise to adjust for that.

And I think in southern California it's somewhat lower than other places, from what I've heard, so --.

One other thing I would mention, kind of early in the report there was a statement that the MPR is the floor price for the RPS procurement. And that's not supposed to be the case.

COMMISSIONER GEESMAN: That would be a very bad fact if it does turn out to be.

MR. KLOBERDANZ: Yeah, it may turn out to be, but it wasn't critical to the way all of the work was done, but it was a statement in the beginning, and it did concern me when I read it.

COMMISSIONER GEESMAN: And if it turns out that way that would be another program design flaw.

MR. KLOBERDANZ: Yeah, it's actually supposed to be a ceiling, as I understand it.

COMMISSIONER GEESMAN: That's our hope.

MR. KLOBERDANZ: To be exceeded only to the extent that PGC funds are available to help exceed it.

And just one last thing I'd mention, and Commissioner Geesman, you know this very well, but earlier, I think just before the lunch break, you were talking about the deliverability burdens that are applied to renewables.

And I just want it to be clear that, at

least in SDG&E's service area, we apply -- whether this is good or not -- we apply the same transmission needs and deliverability assessments to all new generation.

COMMISSIONER GEESMAN: New generation?

MR. KLOBERDANZ: New generation.

COMMISSIONER GEESMAN: What about the legacy generation?

MR. KLOBERDANZ: No, and like I know, you also know that was built under a very different set of rules and circumstances and I guess we could go back and look at that but --

COMMISSIONER GEESMAN: Not certain what you'd gain.

MR. KLOBERDANZ: Yeah, at a minimum I wanted to assure you that, going forward, we do it the same.

COMMISSIONER GEESMAN: What about tomorrow's short-term procurement? You're going to spend ratepayers money procuring resources from who knows where, ranking who knows where on the state's preferred loading order, and you're not going to impose any type of TRCR ranking.

MR. KLOBERDANZ: You're talking about that spot power we try to get --

COMMISSIONER GEESMAN: And I know it's apples and oranges, but we're talking fruit farming here, so --.

MR. KLOBERDANZ: On the spot, you pick it up where you can.

COMMISSIONER GEESMAN: Thank you very much.

MR. KLOBERDANZ: Thank you.

MR. SIMONS: Thank you, Joe.

COMMISSIONER GEESMAN: My agenda says SMUD, so this must be Mike.

MR BATHAM: Thank you, Commissioner Geesman, Melissa, Tim and George especially for allowing SMUD to come and make a presentation here. We appreciate this opportunity.

Building on the analogy that you just made about the bushels of apples going to the barn, I think really the objective that was trying to be established when the RPS was passed was getting the apples to the people who needed to eat them and wanted to eat them and forcing the apples into a bushel and then taking them to the barn is not necessarily the best way to accomplish that goal.

And there's probably ways that we can

improve upon that, and hopefully I can address some of those here.

Again, SMUD appreciates the opportunity to be here. I wanted to highlight our procurement opportunities, and our methodology that we're going through, and hopefully answer all your questions.

One of the things I didn't put on this slide that I should of is contact information, which is just my first initial "m", last name "b-a-t-h-a-m" at smud.org, in case anybody needs to contact me.

I think the work that has been done, with George and the PIER staff here, is admirable, it sets the stage on a statewide perspective, and now the proof is going to be in the pudding on how it's applied regionally. And I know you were talking a little bit about that a few minutes ago.

And that's what's really going to be necessary to make it effective and useful for each of the utilities, including SMUD.

One of the things I wanted to -- since SMUD is different, it's a publicly owned utility and doesn't fit under the same guidelines and rules as the investor-owned utilities but nonetheless SMUD believes that renewables are the thing to do, that the RPS is a program that needs to be implemented, and we're going to strive to implement RPS as we had defined it.

And there's some differences between the way SMUD has defined RPS and renewable procurement that's different from the investor-owned utilities, and I thought I'd just mention that briefly.

First of all, we adopted ours in 2001 before the state actually established its own RPS so our dates are a little bi different, our numbers are a little different, but nonetheless in 2001 we adopted a goal of 10 percent in 2006, 20 percent in 2011 as strictly RPS.

But what we're doing, in addition to that we have a green pricing program where we have residential and commercial customers that have the ability to buy in to either a 50 percent green supply or a 100 percent green supply for their individual residents or businesses, and those numbers are added to our RPS numbers.

So our true goal is 12 percent in 2006 and 23 percent in 2011, and that's reflected on the numbers that you see on the screen. And the numbers that I'm going to show you in a few minutes are going to reflect that.

Also, we put great weight in trying to achieve what we believe is the true goal of the RPS. We don't have the same evaluation criteria that was established in the legislation. Ours tends to be a little more strict.

For instance, we don't give credit for natural gas or solar thermal assist gas projects. We don't give that extra 25 percent. We only give renewable credit for the real renewable solar thermal generation that comes out of that project.

Likewise we don't take any credit for photovoltaics that are installed on roofs or in installations where they're not actually exported into the utility grid. So those aren't part of our numbers, those are in addition.

Fundamentally I think those are the only changes that we have from the statewide perspective.

Recognizing that we needed a bunch of renewable resources we had initially established our selection criteria. Instead of least cost best fit we went through what we call a benefit cost ratio.

And the first criteria that are listed here all feed in to that benefit cost ratio and analysis, and truly it's the energy cost, you know, is it firm energy, when's it going to be available, how's it fit our needs, what are the interconnection requirements and costs.

So we monetize those and we put them into the analysis to determine exactly what the cost would be, and then we compare that to utility need and what the benefits would be.

In addition we looked at resource diversity. We feel very strongly that we want a diverse resource to minimize risk for the SMUD ratepayers. Also we want to have the resources or the power projects close to our resource area if possible.

So we looked at environmental benefits in addition to the generation, we're looking at what are the subsidiary benefits that are associated with that.

For instance, we have a lot of dairy digester landfill gas projects, reduced truck emissions, hundreds of thousands of tons of waste are hauled many miles out of Sacramento into Reno or southern Sacramento Valley, northern valley, out of the Sacramento region.

By taking those waste products, turning them into a fuel resource, it develops electricity. We're reducing those emissions. That's an important goal for our directors. These are all part of what we call our local benefits.

But we look at these other criteria in evaluating projects. Many of these you can't quantify and monetize, but nonetheless they're very important benefits for us when we select projects.

COMMISSIONER GEESMAN: On the financial stability of the project owner, how do your credit worthiness requirements compare to those that the IOU's observe in terms of their negotiation of contracts?

MR BATHAM: I can't answer from the IOU's perspective, because I don't know. What we look at is what is the rating of the company that's proposing to do the project and the likelihood of the company being able to carry out the project for the duration that the project was proposed to do, and we go through analysis to do that. But I can't compare it to the way the IOU's do it.

COMMISSIONER GEESMAN: And my presumption is that very few or any of those companies are rated as high as SMUD is. So you've got some level of dilution of credit every time you sign a contract, don't you?

MR BATHAM: Correct. This graph that I've shown here really is kind of a status of where we are in the procurement process.

I want to highlight a couple of things, starting at the bottom and working our way up. And for those of you who can't see, the bottom axis is 2004 through 2020, and the vertical axis is the gigawatt hours of renewable energy that we're plotting, and the bars that go across from left to right, the first one is existing renewables, those are renewable contracts that we have in place today, they're signed, sealed and in much of the cases energy being delivered.

The next band, which is called planned, are ones that have been approved, permits are in place, everything we feel is in place, such that the project is going to deliver energy at the scheduled time that they're scheduled to deliver it. So it's a high degree of confidence that the bottom two bands are going to be there over the time frame that's listed.

The next big broad band, which says "renewable energy under negotiations and consideration", that's part of our RFO that we issued, although the green is also part of the RFO that's issued.

But the white area that's still under negotiations, there's still some speculation as to whether or not those projects are actually going to be signed, whether or not they're going to get their permits, whether it's an environmental permit or a contract for fuel supply or whatever it may be.

So those are more speculative and it's harder for us to rely on those in the future.

The band above it, which is an important band from SMUD's perspective, are emerging projects. We believe strongly that we need to look beyond existing technologies that are being considered today and include emerging renewables, such as solar thermal, photovoltaics, etc.

Those technologies,k which need to get across the so-called valley of death, to go from viable technologies to commercially available technologies, and we're willing to spend some time and money to work with them and help them across that valley of death, because we believe in the future they're going to help us meet that.

And the right hand side of the chart, the areas that we still need to identify additional resources in the 2020 time frame.

So what this graph shows is we've exceeded our 2006 goal of 12 percent. We've actually got contracts in place that are going to be 15 percent by the year 2006.

2011 is more speculative. There's a lot that needs to be done between now and 2011, or bringing it to the state goal of 2010. We need to do a few things, and I'm going to talk about what those things are, but we feel confident and we're committed to make that 2011 goal.

COMMISSIONER GEESMAN: Now is your preferred structure a power purchase agreement, or are you actually purchasing plants for your own ownership and operation?

MR BATHAM: We own a number of plants. Right now we're focusing on power purchase agreements, but we are helping in construction and owning some new plants, and I can talk about that a little in a minute. Primarily it's wind energy in the Solano area but there's also some dairy digesters that we're working with.

What I want to do here is highlight, now again -- let me go back a second -- keep in mind that the bottom two bands, I'm going to lump them together, those are the ones that are essentially done deals.

The big band in the middle is the ones that are somewhat speculative, and I'm going to do some comparisons between 2006 and 2011 and show some of the concerns that we see and some of the actions that we anticipate taking to overcome those concerns.

First of all, looking only at 2006, I want to show that right now our breakdown by technology is pretty balanced. We've got 35 percent wind, 31 percent geothermal, and 27 percent biomass. So that's a pretty balanced portfolio, and as I said earlier, we like to see a balanced portfolio to mitigate some of the risk.

But as we looked at new technology to satisfy our additional needs in 2011 and on, you'll see that wind is now growing to 61 percent, and geothermal dropped off dramatically. But that's almost an error on the chart because we have one large contract that expires in 2010. If that contract's renewed geothermal will go back up again.

But the message really is here that wind is becoming a dominant resource to help us meet our goals in the future. And because of the intermittency issues and the other issues with wind we're going to have to do something in order to better accommodate that into our system.

And we're doing some studies to do that, and I'll get to those here in a minute.

The point that you raised a little bit earlier about ownership of the wind that's shown there, right now there's 255 megawatts of wind that makes that 61 percent green bar, and of those 180 megawatts are owned by SMUD.

Now they're not all operational to date, but we own the land resource, currently we're building out 100 megawatts, there's another 80 megawatts that are in the planning stage, but we physically own the land and we have plans to develop that resource.

And then in addition to that we have purchase contracts for some additional wind in Solano. We also have some purchase contracts for wind that's outside the Solano area.

Now looking at the existing projects, which is the ones that are likely to be in place, either are in place or are likely to be in place, what I want to highlight here is that only 17 percent of those resources are truly in SMUD's service area.

And this is basically Sacramento County. It's got nothing to do with Yolo County or any possibilities that may happen there. This is all just looking at Sacramento County and a very small sliver of Placer County.

Ten percent are out of state and 73 percent are in California but out of our area. So that's an issue that we've noticed and we're going to have to do something about that.

Comparing it to what we see in 2011 with these emerging projects, and the projects that we're under negotiation and consideration for, you can see that there's only one percent that's in the SMUD area.

So that highlights the issue that we're now having to consider at least, and probably will have to rely on projects that are outside of our area, and what are the issues associated with that. What can we do to change this wraparound to make it more consistent where we have 17 percent in our area. So we're going to take some action to help do that.

As you know, and I'm highlighted it here slightly different, we see the benefits as, especially if they're in our area, that there's going to be no or very low transmission costs.

It's going to build on some of the environmental benefits that I talked about. Also there's an economic benefit concern because we really like to develop projects in a partnership with our ratepayers. Frequently these are small projects, frequently they're small operations, but nonetheless they're important to us.

There are two resource areas that we really have within our service area, biomass and solar. We have currently five projects that are being planned and developed. Three are dairy digesters, and that's what was highlighted here. There are two other small biomass projects that are currently in the finalization of planning and starting construction.

And we've identified, or actually the Energy Commission had identified 535 gigawatt hours of potential biomass energy in Sacramento County.

In addition, solar thermal is a very large resource for the SMUD area, albeit we don't have the same solar insulation and resource that the desert has, we're pretty close. We're between five and 12 percent lower grade solar than the desert, but that number becomes even smaller if you look at the summertime, we're a summer peaking utility and it matches well with our load shape.

So solar thermal is something that we're considering, even though it's expensive. Currently nobody is proposing a project in our area, but nonetheless we have the capability, hopefully, in the future of getting across this valley of death so that these resources can be installed in our service area.

And as you know we're a very strong advocate for photovoltaics, we're the second most photovoltaic friendly utility in the country, at least according to news reports.

So those are the things that we're looking to solve. Here's the actions that we're putting in to place.

Our first priority is to look at the

existing contracts that we have, and let's see if we just can't resign those, because we've already spent a lot of time with those projects, sometime in the future.

But looking at the criteria we developed, we issued an RFO in 2004, June of 2004, essentially the same time or a couple of months before the investor-owned utilities did, doing the same thing, we were trying to attract applicants to supply us with electricity.

In this case we were focusing on purchasing only the energy. But we also had an emerging component with that, because we invited people to propose emerging technologies, knowing that they were going to be more expensive, but we compared those amongst themselves and not among the conventional resources.

We also invited ownership options or combinations of such, where possibly somebody would build a project and they would sell it to us after a few years so that they could have captured the PGC or certain other financial incentives, and then we would own the project later on.

That RFO, we received 72 proposals, six were in our area, 48 were in-state, and a lot of them, 18, were actually out of state, some were actually out of country. We got some from BC, Canada.

So competition is getting such that projects outside of California I think need to be considered.

COMMISSIONER GEESMAN: Are you signing a contract?

MR BATHAM: None for out of state resources to date. Have we signed contracts, yes.

COMMISSIONER GEESMAN: Of the 72 proposals how many resulted in actual executed contracts?

MR BATHAM: One is a contract, one has been approved by the two boards of directors but signatures I don't believe are actually on the piece of paper yet, it should be shortly. The third goes for a vote next month.

COMMISSIONER GEESMAN: So your time frames is not really all that different, in terms of your procurement cycle, from PG&E and San Diego?

MR BATHAM: No, it's not. The next three things, which we're working with the Energy Commission and the PIER staff and I've got a lot of compliments for the PIER staff, they've been very helpful in helping us identify and overcome some of our perceived issues and problems that we want to make sure aren't going to develop into the future so that we can meet those needs in 2011 and beyond.

Because if you'll remember, on that graph not only did we have 2011 at 23 percent, that line continued to go up, because as load growth continues it's still a percentage of that increased load. So we're looking at having more renewable resources beyond 2011.

One of the things we wanted to do was to look at well, what do we have to do in order to own these projects, and how do we structure these projects such that owning them reduces our risk, increases our benefit or the benefits of the project for all parties involved.

So we're looking at the ownership options and we're developing models to help us evaluate on a project by project basis, truly what are the benefits going to be from owning the generator.

In the case of wind, since it's forecasted that we're going to have a higher percentage of wind in our RPS, what can we do in order to seamlessly integrate that wind at high levels into our area.

And we're looking at financial and operational impacts, we're trying to evaluate based upon the seasonal variabilities and the diurnal variabilities.

We're also looking at storage. What can we do in the way of storage to maximize the benefit, increase the dispatchability, and then develop operational procedures so that we can manage those resources and overcome those variables.

COMMISSIONER GEESMAN: Now realistically, isn't it likely that's what's going to end up there is you're going to end up absorbing a fair number of PG&E's costs? Because I'm going to assume that much of the wind is going to be located within PG&E's service territory?

MR BATHAM: The majority of the wind on that graph is in PG&E service territory, correct. It's been --

COMMISSIONER GEESMAN: So they're the ones that are, from an engineering standpoint, going to face the integration challenges, they're going to pas those costs on to you, and you're probably going to fight with PG&E as to whether those are appropriate costs or whether there wasn't some better way to do things.

But isn't that the likely scenario?

MR BATHAM: There will be transmission costs that will be associated with those projects. I don't want to use the words "we're going to fight with them", there's something that needs to be negotiated --

COMMISSIONER GEESMAN: You're going to negotiate with them.

MR BATHAM: Right. And that's started. But we're really dealing directly with the applicant and what are the transmission costs and what are the congestion issues if any to get the power into our area.

COMMISSIONER GEESMAN: The applicant being the project developer?

MR BATHAM: Yes.

COMMISSIONER GEESMAN: Okay.

MR BATHAM: Including ourselves, because we're the developer on a couple of the Solano projects beyond the wind land.

COMMISSIONER GEESMAN: Okay.

MR BATHAM: The next bullet is going beyond the ownership and the wind issues. What can we do to bring wind technologies along through R&D. We actually have an R&D effort working with the Energy Commission and others.

We're looking, in the case of PV, what can be done to lower the installation costs of photovoltaics, even though that does not directly count toward RPS it's still a renewable activity that we have that we feel strongly about.

We can't do much about the manufacturing costs, others are doing that, but installation costs, we're encouraging developers, for instance, to do 100 percent of their new housing developments with PV as an option, and we're being pretty successful along those lines.

We're also looking at PV concentrators, how can we increase the efficiency through concentration of the PV system.

We're also working with some wind developers, Clipper Wind is an example, where they're looking at using a multiple generator and a single tower so that they can capture a higher percentage of the wind resource in some of these lower wind resource areas that was talked about earlier on, the ones that are going to be developing in the hopefully not too distant future. We're involved in that.

We're also looking at ways to accelerate biomass technology, so that you can get the gas developed faster so we can take that gas, convert it into electricity, shorten the life of a landfill for instance, and then turn it around for some other kind of hopefully beneficial activity. So we're doing research on those technologies.

And actually we have a proposal that we're planning on instituting, which will be the first installation of an anaerobic digestion system in the United States. And we're working with the developer on that particular project today.

COMMISSIONER GEESMAN: Are you actively involved, or rather directly involved with the Yolo County landfill?

MR BATHAM: Yes. That's one of the projects that hasn't been pen to paper yet, but seriously getting close.

COMMISSIONER GEESMAN: Okay.

MR BATHAM: And there's actually two Yolo projects.

COMMISSIONER GEESMAN: We had one I think that we were calling the bioreactor?

MR BATHAM: Correct. That's the one that is referred to here, to accelerate the digestive process of that landfill.

COMMISSIONER GEESMAN: Okay.

MR BATHAM: We feel very strongly that, in order to do these things, we're a local control utility, we feel very strongly that local control is important. It allows us the flexibility to implement these programs and get the results to meet our ratepayers needs and we strongly encourage that that be continued.

We also feel strongly that RPS is important, it's the right thing to do, and we support the Energy Commission and the state mandates, and we're going to do everything we can to fit within the constraints of the RPS system.

And with that I'll be happy to answer any questions.

COMMISSIONER GEESMAN: Just have one, Mike. There's a lot of talk about solar thermal and utility consortia to develop solar thermal. Is that something that SMUD could conceivably have an interest in, or do you prefer projects where you're the only utility involved?

MR BATHAM: No, we actually -- it depends on the project. In this particular case we very strongly prefer to be part of a consortia. In fact, we're proposing to lead a consortia to develop that technology, and there are conference calls that are being held, and it's too early to announce anything, but it needs a consortia in order to get the amount of generation that's necessary to bring the cost down and then ultimately, as I said earlier, we're looking at possibly even having that evolve into a Sacramento installation.

COMMISSIONER GEESMAN: Well, I certainly want to thank you for being here. SMUD's had a great program historically, and I think they're lucky to have you associated with it now.

And I'm hopeful that you guys can have some influence on your large municipal cousin in Los Angeles, because I know that they're looking for some new guidance.

MR BATHAM: Thank you.

COMMISSIONER GEESMAN: Thank you.

MR. SIMONS: We're going to see if Dave Olsen is on the line. Dave? You are here.

Okay, so Dave Olsen is going to talk a little bit about the findings form the Tehachapi study group, relative to what we've been talking about today. So, Dave, go ahead.

MR. OLSEN: Commissioner, first I regret that I'm unable to attend to day in person. It's because of meetings of the Imperial Valley study group, which I've been leading the last two days.

The Tehachapi development plan that was filed with the PUC on March 16th is incomplete in two major respects.

First, there was no agreement on the level of upgrade for the transmission routing alternatives necessary to make Tehachapi power deliverable in NP15 or even whether all 4,000 megawatts should be delivered through SP15 and none to NP15. That's one issue.

And secondly, the Tehachapi study did not look at the operability of the grid with 4,000 megawatts o f intermittent windpower connected at the Tehachapi, certainly in a way that addressed ISO concerns about that issue.

In fact, I would like to talk briefly about each of those two points.

On the first point, the level of the

upgrades required. In the Tehachapi study group report PG&E proposed several alternatives. One was a phase shifted tie between the PG&E and the Edison systems at Fresno.

That upgrade would enable PG&E to take about 300 megawatts of Tehachapi power, actually without upgrades, just by installing the phase shifted tie and no other transmission upgrade PG&E would be able to take about 300 megawatts.

PG&E's other two alternative would upgrade its system from Tehachapi all the way to the Bay Area load center. So these are very large scale network upgrades to relieve congestion that would be very expensive.

Several of the parties in the study group believe that it's possible to make Tehachapi power deliverable to NP15 load centers without such large, expensive upgrades, actually perhaps with minimal or even no upgrades.

And at the very least those other alternatives, those less expensive alternatives, should be explored.

Now, I'm not talking about connection of Tehachapi to the high voltage grid, because all parties agree, and I think it's obvious, we have to have connection between Tehachapi and for example the Vincent substation or the Midway substation on the high voltage grid. Rather, I'm talking about network upgrade.

The study group met Tuesday of this week and has now agreed to address this issue through production simulations that will be performed by the ISO.

The first thing is to develop a base case. The study group has not done that to date, primarily because of the objection of PG&E to do so, but the base case would add Tehachapi wind power without any new transmission facility.

So that by adding Tehachapi generation in increments we'll be able to see which facilities become overloaded, and at which point, as the various increments of wind power are added to the system.

The ISO model that will be used dispatches generation on variable costs, and because wind has near zero variable cost essentially the model will dispatch the wind first and back more expensive resources down.

So if it turns out that some of the fossil resources that are backed down are needed for either RMR or for support of remedial actions schemes, that's something that we could address later on a case by case basis after we see how much wind can actually be accommodated without new transmission.

This issue of what level of upgrades are needed and whether or not renewable energy should be required to remove all congestion or to, whether renewable energy, in this case wind power, should be physically deliverable to load centers, Bay Area load center for example, have a great influence on RPS implementation since obviously these large network upgrades would take years to be approved and built.

And if it is in fact the case that we can connect some significant portion of Tehachapi wind with minimum upgrade that's something we can do now and still have the possibility of meeting the accelerated energy action plan timeline for RPS compliance.

So that's why this is a very important issue. And I think we're set now to begin to look at this issue in a good way in the study group.

On the second point, on integration of wind power on to the grid, there are a range of opportunities that many of the parties in the study group think it's important to explore in order to increase the operating flexibility of the ISO grid.

The ISO met with the Tehachapi study group several months ago and reported the effective decline in the operating flexibility of the grid, due in part to increased use of new combined cycle units, which have very little load following capability.

So the ISO is faced with declining flexibility at a time when we're seeking to add more intermittent wind power. So, in response, there are a number of things that should be explored.

One we've talked about in the study group is a different operating regime for the Helms pump storage plant. The Helms was originally designed to provide very flexible operation across almost its entire output range in both the pumping and the generating mode.

It has not been operated with anything like that degree of flexibility, and it's unclear whether or not the plant is physically capable anymore of meeting its design criteria, design specification.

But even if it turned out that new pump turbine equipment were necessary and provided substantial flexibility that made it possible to accept much more intermittent wind power, hardware upgrades at Helms could be considerably less expensive than a large scale transmission upgrade. So that's one of the things we'd like to explore in the production simulation.

Another is the pumping capacity in the state water project. There are several thousand megawatts of pumping and some generating capability in the aqueduct of the state water project. That is another potential source of regulating flexibility that could help provide more operating flexibility for the ISO and thus increase the ability to accept more intermittent wind power.

These are some of the things that we hope to explore. There is one more very important point on this integration issue. Whatever the Tehachapi study group does with the production simulation, we would like to coordinate that work of looking at integration and flexible operation of the grid with the Energy Commission PIER study that Nora Yen talked about early this morning.

She mentioned the intermittency analysis project that is just getting underway. I think the important thing here is that the Energy Commission has sponsored three integration cost studies to date, and we're now beginning a fourth, essentially, with this PIER intermittency analysis project.

I think for all the parties involved it's important to make this study the final, definitive one. And to have something that produces results that the ISO will accept, the IOU's will accept, the regulatory agencies will accept, so that we can put this behind us and go forward.

And to that end, the Tehachapi study group, at its meeting on Tuesday of this week, requested up to contact both CPUC Commissioner Gruenech, who will be the assigned Commissioner on a new RPS transmission OII that the PUC will open in August, and also to you, Commissioner Geesman.

That's the genesis of my communication with you earlier this week on this issue of seeking to coordinate whatever the Tehachapi stud group does with the CEC PIER intermittency project, in hopes of agreeing on a steady scope, steady assumptions that can be agreed on by all parties so that we can have a definitive result.

I'd be happy to answer any questions, or --.

COMMISSIONER GEESMAN: Well, those are worthy objectives. I'm not certain I believe in definitive results. I think this is an area that we're going to be studying for a number of years, but I do think that it's important to scope the next generation of study in such a way that it does actually result in some concrete conclusions.

From my perspective it's imperative that each of the affected utilities, as well as the ISO, feel some ownership of those results. And feel that the study properly addresses the concerns that both the PTO's and the ISO are likely to have.

MR. OLSEN: And I think that's what we're looking for, looking for results that really provide a solid basis for quality decisions near term, and, as you put it, if all the parties feel ownership that's what we need right now.

COMMISSIONER GEESMAN: Now, regarding the pumped hydro, is the City of Los Angeles a participant in the Tehachapi study group?

MR. OLSEN: Only nominally. We have made, and I will say that I personally have made a sustained effort to get the Department of Water and Power to participate actively. ?They have declined to do so.

They send a representative to meetings, but that person never participates, doesn't say anything, and we have made several specific requests to the Department to contribute some studies in a substantive way, and they have declined all our requests to do so.

So, in terms of using the pumping and generating capability at Castaic, for example, that's something that we have not been able to get the Department to even consider.

COMMISSIONER GEESMAN: Well, I expect he's got a lot of things on his plate, but there is new leadership there today. So, I think we probably ought to wait for the mayor to get his feet on the ground and hope that maybe, going forward, that they will have a more active interest in that region than they've had to date.

MR. OLSEN: We'll certainly do that.

COMMISSIONER GEESMAN: David, thank you

very much. Ah, just a second, Chifong has a question for you.

MR. OLSEN: Hi, Chifong.

MS. THOMAS: Hi, David. I'd just like to correct some impression that I have anyway about this, you're saying that PG&E objected to doing any study, production simulation studies, for trying to incorporate Tehachapi generation without transmission.

I don't believe that would be the case, because what happened is that the production simulation program, to be run by the ISO, and we don't have the capability at PG&E to run them. And so, you know, it's not because we objected to it that it wasn't running, the ISO runs them. So that's one thing.

The other thing is that, in the transmission planning study, there are two parts to it. One part is reliability, which is the power flow stability and so on. And the other part is economic, which is the production simulation runs.

Once we've identified problems with the reliability part of it the production simulation runs would decide whether it is economic to build certain upgrades or not. So both had to go in.

Now, if we decide, based on the production simulation runs, that a upgrade is not economic, and that is fine, what we need to do is understand that planning studies that's done today, that what planning decided to build the transmission upgrade today is what the operators need to live with tomorrow.

And so if we decided that it is not economic to build certain transmission, it is okay to do so provided everybody understands that that is a limitation that would be built into tomorrow's system.

As far as Helms is concerned, there is the Big Creek Fresno tie, the studies being conducted for that, in the earlier study as well as the continuing study under the PUC direction is not just the fact that we need a phase shifter at Fresno, at Big Creek to make this happen.

Edison's system also needs to be upgraded. And I think that Jorge Chacon is running studies as we -- well, maybe not as we speak, but anyway he's running studies. And I think in a few months we may be able to come up with some answer as to what level of transfer is feasible at Big Creek Fresno.

But in any case the study would have to be completed by the end of this year.

MR. OLSEN: I think it's a good thing that, at our meeting earlier this week, that we've agreed to expand the study of the tie between the PG&E and Edison systems to look beyond just the 300 megawatts.

It certainly will require upgrades to the Edison system as well as the PG&E system, but the potential for having in effect that upgrade, if it's proved out, function as a new 500 KV line, potentially, for taking more power from Tehachapi.

So that's an excellent thing. This is a new development now in the Tehachapi study group, so that's great.

On the point about the objection, the earlier objection to doing a base case with adding Tehachapi wind but no new transmission facilities, essentially that's water over the dam. It is my distinct recollection from our meetings that PG&E did object to having the ISO run that particular case, but we're going forward now and doing it.

So I think that's the important thing, that we are going to study that now, and I think that will help us produce much better results.

MS. THOMAS: I guess it's water over the dam there, because my recollection is totally different than yours, so I guess we'll just agree to disagree.

COMMISSIONER GEESMAN: Well, every now and then you guys send me minutes from the Tehachapi study group, so, always happy to read about them.

Do we have anything else on the day before a three day weekend. Hal?

MR. ROMANOWITZ: I won't take very long here. Thank you very much.

COMMISSIONER GEESMAN: David, thank you very much, but why don't you stay on for any other questions that we have.

MR. ROMANOWITZ: Hal Romanowitz again, and I appreciate, incidentally, Dave's comments, and really the significant things here in the group, looking at these notes there's one thing that's very significant.

There appears to be a disconnect between what the PUC is publishing in the TerKeurst proposed decision, essentially on pages seven and eight she's calling out specifically this program, with the CEC PIER group identifying the options to use to quantify the network benefits.

And essentially in the proposed Decision they're saying that they're really planning to use your numbers in their work. However, when you look at the way you're doing your work it doesn't lend itself to being used.

And the shortcomings are, number one, on the existing nodes work, which I think identifies a lot of good opportunities, the shortcoming there is that there are no per unit costs in any of the things that have been identified, so that it can't be then directly used by the PUC.

Secondly, and more significantly, there is no identification of network benefits in this process here associated with any new facilities that are built. So that the cost of those facilities go 100 percent against the projects that are associated with them.

And specifically on the Tehachapi group, on segments one and two, which are really network re-enhancements or enhancements to a very large degree, the significant network benefits, without question, are going to penalize any Tehachapi projects quite unfairly. So there needs to be a quantification of those network benefits.

And third, probably the single most dramatic potential in the state to use existing transmission capacity is completely missed because it's not there 100 percent of the time, but specifically, for example, Path 15 south to north, has very substantial capacity available summer on peak, and a huge capacity.

The reason that it probably didn't show up in this study is that off peak return economy energy is being returned to the Pacific northwest, and that's really just stuff that should be able to be delivered any time, so that's an extremely valuable resource that ought to be picked up in this process and quantified.

COMMISSIONER GEESMAN: Thank you, Hal. One of the glories of our PIER process is I don't seem to know much about these intermittent studies until we have workshops. So Dave, I didn't have any idea of what you were talking about in your earlier e-mail to me a couple of days ago. I have less idea of what Hal's talking about.

But rest assured I will get myself fully briefed over the course of the next week and try and figure out what's going on.

MR. ROMANOWITZ: Thank you very much.

COMMISSIONER GEESMAN: Any other comments? Great. I want to thank everybody for hanging in there on the Friday before a three day weekend. It's been a very informative day.

(Thereupon, the workshop ended at 5:02 p.m.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 21rst day of July, 2005.

PETER PETTY